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List of Abbreviations

AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
APWA	American Public Works Association
ASME	American Society of Mechanical Engineers
CGA	Common Ground Alliance
CLSM	Controlled Low-Strength Material
CSA	Canadian Standards Association
DAMQAT	Damage Prevention Quality Action Team
DIN	Deutsches Institut fur Normung (the German Institute for Standardization)
DIRT	Damage Information Reporting Tool
DOT	(U.S.) Department of Transportation
Dt Ratio	Diameter-to-Thickness Ratio
ECDA	External Corrosion Direct Assessment
EGIG	European Gas Pipeline Incident Group
EMAT	Electromagnetic Acoustic Transducers
EN	(European Standard designation)
EPRG	European Pipeline Research Group
ERCB	Energy Resources Conservation Board (formerly Alberta Energy and Utilities Board - EUB)
ERW	Electric Resistance Weld
ESR	Epoxy Sleeve Repair
EUB	Alberta Energy and Utility Board
FCC	Federal Communications Commission
FEA	Finite Element Analysis
FRC	Fiber-Reinforced Concrete
GIS	Geographic Information System
GMAW	Gas Metal Arc Welding
GPR	Ground-Penetrating Radar
GPS	Global Positioning System
GRI	Gas Research Institute
GTAW	Gas Tungsten Arc Welding
HAZ	Heat Affected Zone
HCA	High-Consequence Area
HDPE	High Density Polyethylene
HF	High Frequency
HSE	Health and Safety Executive (HSE) Hazardous Installations Directorate (United Kingdom)
ILI	In-Line Inspection
km	Kilometer
LDPE	Low Density Polyethylene
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic Flux Leakage
MPI	Magnetic Particle Inspection
NAPSR	National Association of Pipeline Safety Representatives
NDT	Non-Destructive Testing
NEB	National Energy Board (Canada)

NPS	Nominal Pipe Size
NTSB	National Transportation Safety Board
OD	Outer/Outside Diameter
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration
PDAM	Pipeline Defect Assessment Manual
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipeline Inspection, Protection, Enforcement, and Safety Act
PP	Polypropylene
PPTS	Pipeline Performance Tracking System
PRCI	Pipeline Research Council International, Inc.
PSA	Petroleum Safety Authority (Norway)
psi	Pounds Per Square Inch
SCC	Stress Corrosion Cracking
SES	Stress Engineering Services
SMYS	Specified Minimum Yield Strength
TESS	Texas Excavation Safety System, Inc
TOFD	Time-of-Flight Diffraction
TSB	Transportation Safety Board of Canada
UKOPA	UK Onshore Pipeline Operators Association
ULCC	Utility Location and Coordinating Council
U.S.C.	United States Code
UAV	Unmanned Airborne Vehicle
UT	Ultrasonic Testing
UTS	Ultimate Tensile Strength
VSCC	Virginia State Corporation Commission

Executive Summary

This report reviews and summarizes the current state of knowledge and practice related to mechanical damage in natural gas and hazardous liquid steel pipelines, with particular focus on transmission pipelines. Comprehensive voluntary interviews were conducted with 10 pipeline operators who represent a diverse cross section of industry professionals in the United States, Canada, and Europe. The interviews, which focused on operator practices for detection, characterization, and mitigation of mechanical damage on both gas and liquid transmission and gas distribution pipelines (the latter examined for comparison purposes), provided an invaluable source of data for the development of this report. Operator practices associated with prevention of mechanical damage primarily resulting from excavation damage were also extensively covered in the interviews. The inquiry primarily included pipelines that comprise transmission systems, but gas distribution companies also reported on their experience with distribution systems consisting of both steel and plastic pipe, the latter reviewed for a comprehensive discussion of the operator's damage prevention programs and issues. Pipeline geographic locations included remote and rugged terrain, rural areas, and constrained urban environments.

Mechanical damage is defined in the context of this report as localized damage to the pipe resulting from contact with an object. "Localized" means that the damage is confined to a part of the pipe's cross section and extends along a portion of the pipe's axis. Damage from contact can occur during pipe manufacture and transport, although most mechanical damage that could lead to a failure occurs as excavation damage, either during pipeline construction, operation, or maintenance or, more prevalently, from third-party activity over or near the pipeline. In-line inspection (ILI) has been demonstrated to be the most common method for detection of prior mechanical damage, and the capabilities and limitations of the existing ILI tools are examined in this context.

The characteristics of localized damage are reviewed. The authors emphasize that the severity of both immediate and prior damage depends on a number of parameters, including the geometric characteristics of the defect, the properties of the pipe steel, and the stresses and loadings on the pipeline. The evaluation of the threat to pipeline integrity posed by prior mechanical damage is accomplished by various methods, ranging from the application of basic techniques suitable for simple go/no-go screening, to advanced techniques that may require detailed material modeling and laboratory calibration.

The prevention of mechanical damage, including the development of regulatory guidance to evaluate the effectiveness of mechanical damage management methods, is discussed. In addition, other significant preventative measures are reviewed, including the one-call system that enables individuals who are planning to excavate to contact the appropriate local one-call centers, campaigns to promote public awareness, and widely applied measures to enforce safe excavation practices. The discussions in this section are not meant to be a comprehensive discussion of damage prevention best practices, but are presented to provide information on mechanical damage prevention in the context of excavation damage prevention and control. Emerging prevention technologies are also summarized, including various encroachment monitoring systems to detect and interpret incidents of unanticipated encroachment and to monitor contact with an object during excavation, as well as the use of electronic "white-lining" to delineate an excavation area through the use of global positioning systems (GPS) and electronic mapping technology.

It is noted that once mechanical damage has occurred, practical options to mitigate its impacts appear limited to pressure reduction or shutdown, which are performed either to permit immediate repair or to enable excavation for more in-depth evaluation. Several repair methods are available to remediate mechanical damage, including sleeves, recoating, and cutouts. To address significant damage, operators generally apply Type A (non-pressure containing) or Type B (pressure-containing) steel sleeves, although composite and other repairs are also performed.

Canadian, U.S., and European pipeline regulatory standards and practices for monitoring and addressing the impacts from mechanical damage are compared. While variations are noted and primarily relate to differences in focus (for example, prevention and response versus detection), most industry guidelines and recommended practices were found to be widely shared. In fact, many are based on documents originally prepared by U.S. regulatory agencies, with direct input from international colleagues. The growing volume of legislation across continents underscores the perceived importance of the need to reduce the likelihood of and consequences from pipeline mechanical damage failure.

Issues and gaps in industry knowledge and regulatory requirements for the prevention, detection, and remediation of mechanical damage were identified based on an examination of published literature, proprietary reports, and Pipeline and Hazardous Materials Safety Administration Workshop on Mechanical Damage findings, as well as studies commissioned by the Pipeline Research Council International (PRCI) and others. Key gaps identified include:

- Better one-call enforcement, improved communications, an improved understanding of the effectiveness of different prevention methods and better ways of enhancing public awareness
- The need for ILI technology that more accurately detects and assesses the severity of prior mechanical damage
- Methods to determine the need for immediate action or pressure reduction
- Validated methods to assess the remaining service life of pipelines impacted by mechanical damage
- Guidelines for the selection and application of composite repair systems
- Improved confidence in the long-term performance reliability of all repair systems

1 Introduction

This report has been developed in accordance with the Statement of Work and proposal submitted in response to the Request for Proposal for Technical Task Order 16 (TTO 16), "Mechanical Damage Study."

1.1 Overview

According to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), excavation damage has accounted for one-fifth of all significant[1] pipeline incidents on hazardous liquid and natural gas transmission pipelines (both onshore and offshore) over the past 20 years. On gas distribution systems, excavation damage as accounted for more than 36 percent of all significant pipeline incidents, far greater than any other cause of pipeline failure. Excavation damage was listed as the cause of more than one-third of all serious pipeline incidents (those involving a fatality or injury requiring in-patient hospitalization.) Most excavation damage results in immediate failure due to line hits; however, a few highly visible incidents in the 1990s resulted from mechanical damage inflicted on the pipeline from prior excavation damage. As was evidenced in the notable incidents in Edison, New Jersey, and Bellingham, Washington, unreported mechanical damage can have serious consequences.

Significant investments have been made by the Pipeline and Hazardous Materials Safety Administration (PHMSA), the pipeline industry, and stakeholder organizations to increase public awareness of the risks of excavation in pipeline corridors. Likewise, much effort has been invested in research to detect mechanical damage using in-line inspection (ILI) technologies, evaluate the severity of mechanical damage, and develop mitigation measures. However, no single endeavor has adequately addressed each of these considerations or their interrelationships in sufficient detail, with adequate industry support for the outcome, to be broadly accepted by all stakeholders as the benchmark for advancing the technology to address mechanical damage issues.

In a collaborative effort to address the problem, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) held a major public workshop from February 28-March 1, 2006, in Houston, Texas, to discuss issues associated with the role of technology in preventing, detecting, characterizing, and mitigating mechanical damage risks to energy pipelines. The workshop was organized in cooperation with several stakeholder organizations and drove the scope for this major synthesis study on mechanical damage. The results of the workshop and the information shared were intended to: 1) further research on mechanical damage; 2) document the state of current damage prevention, detection, and characterization technology; and 3) establish a clear direction for issues to be addressed by the mechanical damage study. More than 250 people attended the workshop in person or via web cast. The workshop presentations are available at http://primis.phmsa.dot.gov/rd/mtg_022806.htm.

1.2 Mechanical Damage in Perspective

Major progress has been made over the past 20 years by PHMSA, the pipeline industry, and research and trade associations with regard to the reduction of serious pipeline incidents (those resulting in a fatality or

[1] PHMSA defines Significant Incidents as those incidents reported by pipeline operators when any of the following conditions are met: (1) fatality or injury requiring in-patient hospitalization; (2) $50,000 or more in total costs, measured in 1984 dollars; (3) highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or (4) liquid releases resulting in an unintentional fire or explosion

injury requiring in-patient hospitalization) from all causes including excavation damage, corrosion, human error, natural force damage, material failure and other outside force damage. As illustrated in Figure 1.1, the data indicates a downward trend of serious incidents from all causes on all types of pipelines from 1988-2008.

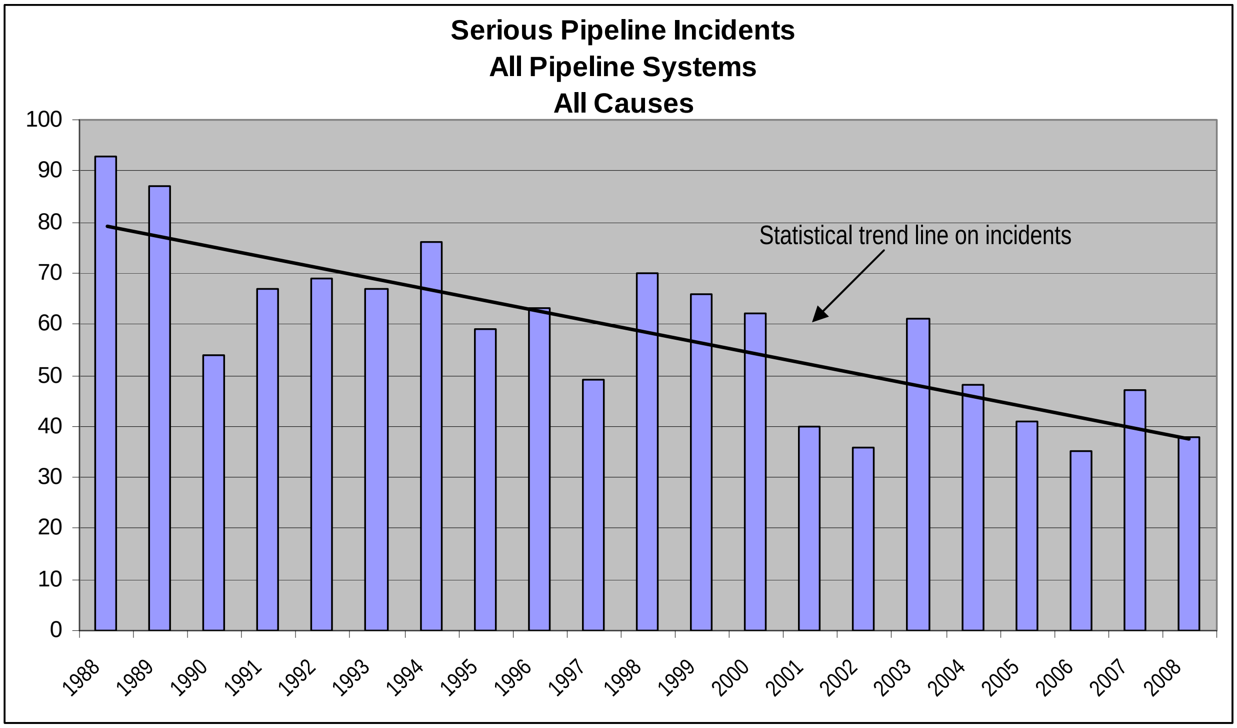

Figure 1.1 – Serious Pipeline Incidents – All pipeline systems (onshore and offshore)
Source: DOT/PHMSA Pipeline Incident Data

Figure 1.2 indicates a similar trend for serious pipeline incidents caused by excavation damage for the same 20- year period. This positive trend is the result of a broad array of initiatives at all levels designed to engage all stakeholders in efforts to reduce the risk of damage to underground facilities.

Table 1.1 shows the primary causes of serious pipeline incidents from 2000 to 2008 as a percentage of the total number of serious incidents for all pipelines. Other than failures for unknown reasons (categorized under All Other Causes), failures due to excavation damage remain a primary cause of serious pipeline incidents.

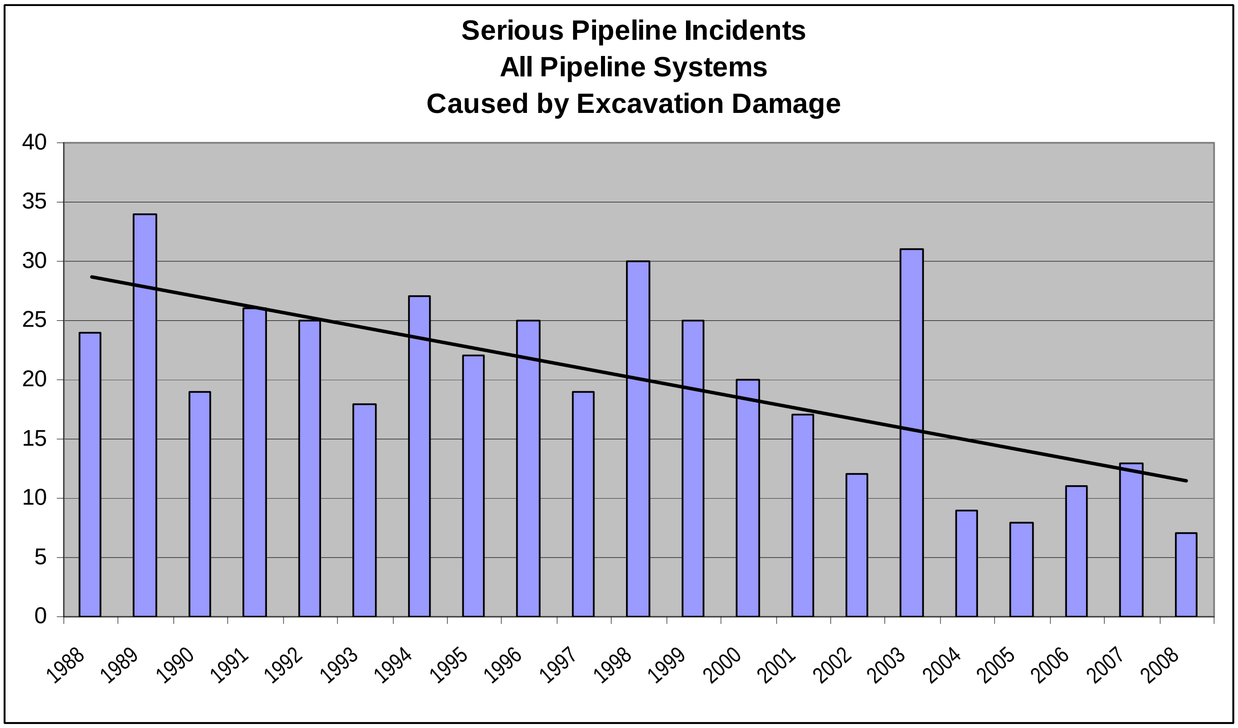

Figure 1.2 – Serious Pipeline Incidents Caused by Excavation Damage - All pipeline systems (onshore and offshore)
Source: DOT/PHMSA Pipeline Incident Data

Table 1.1 Causes of Serious Pipeline Incidents - All Pipeline Systems (PHMSA 2000-2008 data)
(Leading Cause Category Highlighted)

Cause Category	2000	2001	2002	2003	2004	2005	2006	2007	2008
Corrosion	8.1%	7.5%	5.6%	0.0%	6.3%	4.9%	8.6%	6.4%	5.3%
Excavation Damage	32.3%	42.5%	33.3%	50.8%	18.8%	19.5%	31.4%	27.7%	18.4%
Human Error	6.5%	7.5%	13.9%	6.6%	12.5%	19.5%	5.7%	4.3%	7.9%
Material Failure	11.3%	2.5%	11.1%	8.2%	10.4%	2.4%	2.9%	2.1%	5.3%
Natural Force Damage	4.8%	7.5%	0.0%	4.9%	12.5%	4.9%	2.9%	2.1%	2.6%
Other Outside Force Damage	0.0%	0.0%	2.8%	4.9%	14.6%	26.8%	25.7%	19.1%	23.7%
All Other Causes	37.1%	32.5%	33.3%	24.6%	25.0%	22.0%	22.9%	38.3%	36.8%
Total No. Incidents	62	40	36	61	48	41	35	47	38

Mechanical damage can cause either immediate or delayed pipeline failure, with the vast majority of failures occurring at the time of impact. Immediate failure typically occurs when construction equipment punctures the pipe and produces a leak at the time of damage. Understandably, a disproportionate share of the consequences of failure in terms of serious injuries and property damage occur with immediate damage failure as people are generally present when the damage occurs. Mechanical damage less frequently serves as an initiation site for crack formation and eventual failure. The notable pipeline failures in Edison, New Jersey, and Bellingham, Washington, serve as examples of damage to pipelines that resulted in delayed catastrophic failure. Since 2002, there have been only four reported incidents caused by failure of previously damaged onshore gas transmission pipe. It is difficult to state with certainty why this number is low. Information reported by INGAA indicates that natural gas operators' integrity management programs are not reporting a significant number of repairs of previously damaged pipe. The very few incidents that have been reported are most likely a combination of prevention of new, unreported damage and unaddressed damage to pipelines, low-failure probabilities of much of the existing excavation damage, and attrition of the existing damage by repair. By far, according to INGAA, is the success of damage prevention programs, including education, notification, regulation, and enforcement in contributing to the low number of incidents due to previously damaged pipe.

2 Background

Recent integrity management reviews have identified difficulties in assessing the mechanical damage threat to pipeline integrity. The pipeline industry, as well as organizations such as the Common Ground Alliance (CGA), has made a significant effort to increase public awareness of the risks of excavation in pipeline corridors. The pipeline industry has also supported research for the prevention of mechanical damage, detection using in-line inspection (ILI) and other technologies, characterization of damage, and evaluation of severity, as well as the mitigation of existing damage. Pipeline companies consider all of these preventative and mitigative factors in combination to manage mechanical damage threat.

2.1 Problem Statement

Federal regulations require pipeline operators to identify and address integrity threats applicable to their own pipeline systems. In nearly all cases, mechanical damage is a threat that must be addressed. Pipeline companies and their regulators must determine if the threat prevention, detection, characterization, evaluation, and mitigation measures that pipeline operators include in their Integrity Management Programs are adequate.

Mechanical damage is, by its nature, complex. There are a myriad of ways in which a pipeline can be damaged, under conditions that vary from location to location. As well, a pipeline's properties and condition, and therefore its propensity for damage, are determined by the system's construction, operation, and maintenance history. Mechanical damage impacts safety, the environment, and system reliability. The consequences can vary from immediate to delayed and from minor to catastrophic.

Managing the threat of mechanical damage is equally complex. For example, existing damage located belowground could be managed by identifying the source of the damage and performing an excavation to remove the damage. However, excavating near a pipeline carries the risk of causing additional damage itself, and, by removing the constraints imposed by backfill, generating loadings that could lead to pipe failure. While other methods of managing existing damage are possible, each has inherent limitations. As a result, a variety of tools and techniques must often be employed to manage existing mechanical damage, according to the unique characteristics of any one pipeline segment.

There are also many ways of managing conditions to protect against future mechanical damage, which include the installation of barriers or other protection or monitoring systems to detect when damage is imminent or is occurring. The best way to manage future damage is widely recognized to be through prevention and mitigation strategies.

Addressing existing damage and the potential for future mechanical damage is one part of threat management. The consequences of a failure due to damage are essentially set by physics. Immediate and catastrophic failures often endanger human life. Delayed and non-catastrophic failures may more strongly affect the environment. Both have significant financial consequences through impact on reliability or continuity of service.

2.2 Current Regulatory and Industry Practice Perspectives

In the United States, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) is responsible for regulating onshore (and some offshore) pipelines. Current regulations provide simple acceptance criteria for evaluating the need to remediate existing dents when found. These criteria are based primarily on depth and location. These criteria do not consider complex, or interactive, behavior.

In addition, industry standards and regulations do not provide guidance for establishing and evaluating measures to reduce integrity threats before final mitigation measures can be employed. Nor do they establish a timeframe for mitigation of the integrity threat discovered by an ILI inspection. Finally, industry standards and regulations do not provide guidance for evaluating the likely effectiveness of various management options to reduce or eliminate mechanical damage threat.

In order to provide more guidance on addressing the mechanical damage threat, PHMSA and the pipeline industry are co-sponsoring research to develop technological solutions, to improve the effectiveness of direct assessment and consensus standards, and to create and promote new knowledge for decision makers.

2.3 Project Scope Overview

This report discusses mechanical damage issues relating to the integrity of both natural gas and hazardous liquid pipelines. The report begins with a definition of mechanical damage developed through discussions with a wide variety of stakeholders. Mechanical damage incident history is reviewed, along with prevention techniques, detection and characterization methods, assessment procedures, and mitigation measures. Regulatory procedures for evaluating and monitoring the effectiveness of mechanical damage threat management methods are also discussed. The report examines the types and prevalence of accepted technologies utilized to evaluate mechanical damage; however, no recommendations are made in support of any particular technology. In addition, the report identifies gaps in technology which impact the understanding, identification, assessment, management, and mitigation of mechanical damage to pipelines. Gaps in associated regulations and industry standards are also addressed.

In gathering the study data for this report, the authors collaborated with major industry trade organizations, pipeline operators, pipeline regulators, and industry experts, both in the United States and abroad. Industry input and public comment were sought to ensure broad acceptance.

3 Literature Review

3.1 Literature Search and Database

A search of the literature on dents and mechanical damage in pipelines, including technical papers, reports, and articles, was conducted to identify current and informative documents for understanding and managing the threat of mechanical damage. The authors wish to thank the Pipeline Research Council International (PRCI) in particular for providing unrestricted access to its wealth of research reports on all aspects of mechanical damage.

From these sources, the authors compiled a Microsoft Access database, following a format similar to that developed for the 2004 study on Stress Corrosion Cracking developed by Michael Baker Jr., Inc. The database, which contains basic bibliographic information for more than 200 documents, is described in Section 3.3 below.

3.2 Recommended References

The majority of pipeline mechanical damage documentation focuses on particular aspects of the damage management process – specifically, the various causes of mechanical damage and the ways by which it can be prevented, or the methods for locating, assessing, and remediating mechanical damage once it has occurred. No documents that provide a comprehensive overview of all of the issues associated with the damage management process were identified.

Basic information concerning the nature, frequency, and causes of mechanical damage incidents is available for the United States, Canada, and Europe, from the Pipeline Safety section of the U.S. Department of Transportation (DOT) web site, the Canadian National Energy Board (NEB) web site, and the European Gas pipeline Incidents data Group (EGIG) web site, respectively. Researchers have frequently reviewed the data. Examples of such efforts include the reports on U.S. data by Kiefner and Associates (Kiefner et al., 2001) and on European data by EGIG (2005). Other web sites provide information for pipelines carrying particular types of products (such as oil pipelines), or for those in particular locations (i.e., offshore pipelines) or geographic areas. However, comparisons among the datasets are difficult because the data are gathered according to different criteria.

A good source for a summation of damage prevention technologies is the Process Performance Improvement Consultants P-PIC report, which was commissioned by GRI/PRCI (Hereth et al., 2005). Access to the main report is restricted. Key findings were presented at the International Pipeline Conference (IPC) 2006 (Leewis, 2006; Hereth et al., 2006). For information and guidance on other aspects of damage prevention, such as one-call systems and excavation monitoring, the reader is referred to the American Petroleum Institute (API) publications API 1162 (2003) and API 1166 (2005), and also to the Common Ground Alliance (CGA) recommended and best practices publications (CGA, 2008).

Although there have been significant advances in the design of in-line inspection (ILI) hardware and software to detect and characterize dents and mechanical damage, there does not yet appear to be a document that provides an adequate overview of new technological developments, in part because the accuracy and reliability of current inspection tools is an area of ongoing research and capabilities are continually changing.

The development of methods to assess the severity of mechanical damage in gas pipelines according to current U.S. regulatory requirements is reviewed in the GRI report and corresponding IPC 2002 presentation by Rosenfeld et al. (Rosenfeld 2001; Rosenfeld et al., 2002). The equivalent guidance for oil pipelines appears in API 1156 (1997; 1999). Methods developed in Europe, where performance-based approaches are predominant, are summarized in a paper by the European Pipeline Research Group (EPRG) (1999). More recently, the *Pipeline Defect Assessment Manual* has been developed in an international Joint Industry Project (JIP). The manual itself is proprietary to JIP members, but much of the information concerning dents and mechanical damage has been published (Cosham and Hopkins, 2002, 2003).

Techniques and procedures for repairing mechanical damage are reviewed in a report that was commissioned by PRCI, originally produced by Battelle, and subsequently updated by CC Technologies (Jaske et al., 2006).

The experiences of operators in applying regulatory guidance to the operation and maintenance of their pipeline systems, often within the context of the U.S. requirements for formalized Integrity Management Plans, are illustrated in several papers presented at IPC 2004 and IPC 2006 (McCoy and Ironside, 2004; Adams and Zhou, 2004; Warman, 2006). These papers provide insight into the challenges that are faced and the issues that arise from technical, operational, and managerial viewpoints.

Research on mechanical damage has been in progress for more than 40 years. Much of the early work is collated and reviewed in the GRI report by Kiefner and Associates (2000). Two reports commissioned by PRCI and prepared by Battelle and by CFER review the more recent studies and identify the "gaps" to be addressed by ongoing research (Leis and Hopkins, 2003; Fuglem, 2007); parts of these reports have also appeared in open publications. Many of the gaps identified by these reports are the subject of ongoing research (refer to Chapter 11 of this study).

The regulatory requirements for managing the threat of mechanical damage vary from country to country. In the United States., operator response is governed by the Code of Federal Regulations (CFR) 49 CFR Parts 192 and 195, and corresponding American Society of Mechanical Engineers (ASME) guidance in ASME B31.8, ASME B31.8S, ASME B31.4, and API 1166. In Canada, the equivalent regulatory standard, set by the Canadian Standards Association (CSA), is CSA Z662. In Europe, the European Union has established EN 1549 (for gas pipelines) and EN 14161 (for liquid pipelines). The U.S. standard is more explicit and prescriptive than those formulated by other countries. The Australian Standard (AS) guidance AS 2885 has recently been revised, particularly with respect to damage prevention, and merits reader attention.

3.3 Database Description

The mechanical damage Microsoft Access® database developed by the authors of this mechanical damage report contains basic bibliographic information for more than 200 documents and provides brief abstracts[1]. To facilitate searches, the database provides keywords associated with many of the reports. Upon accessing the database, the user views a menu (shown in Figure 3.1) that permits either a general review of the data or provides search options to obtain more specific information.

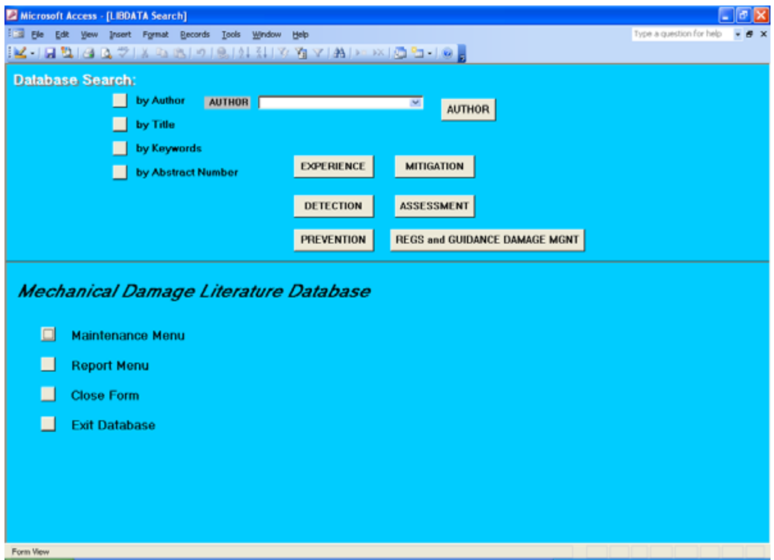

Figure 3.1 – Mechanical Damage Database Menu

A typical report is displayed in Figure 3.2.

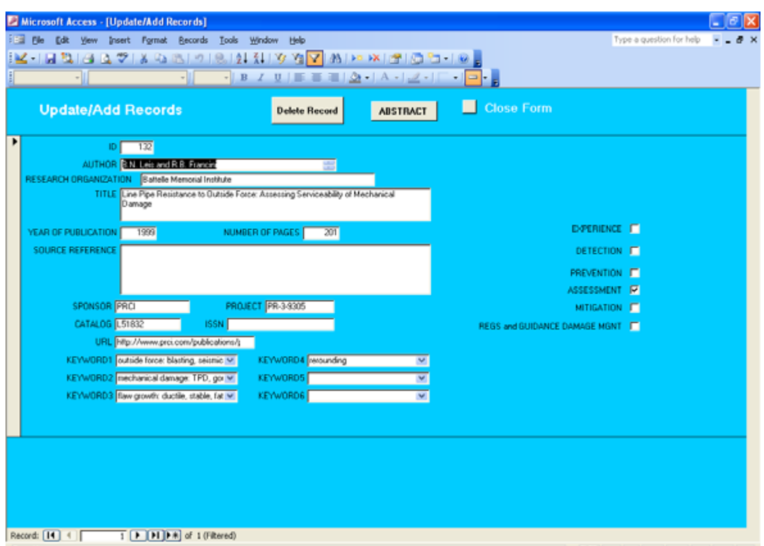

Figure 3.2 – Mechanical Damage Database Typical Report

A copy of the database can be accessed by double-clicking on the icon. 

[1] Some PRCI reports may be available only to PRCI members.

3.4 References

The references listed below are those cited in the narrative for this chapter. The reader is referred to the database to obtain a complete listing of relevant documents.

1. Adams and Zhou. (2004, October). In-service dent management from an operator's perspective. Paper 0437 presented at ASME 5th International Pipeline Conference, Calgary.
2. American Petroleum Institute. (1997 and 1999). Effects of smooth and rock dents on liquid petroleum pipelines (Phases I & II). API Publication 1156.
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4. American Petroleum Institute. (2005, November). Excavation, monitoring and observation. API Recommended Practice 1166. (First Ed).
5. Common Ground Alliance. (2008, March). Damage prevention best practices, Version 5.0.
6. Cosham and Hopkins. (2002, September). The pipeline defect assessment manual. Paper 27067 presented at ASME 4th International Pipeline Conference, Calgary.
7. Cosham, A. and Hopkins, P. (2003, July). The effect of dents in pipelines – guidance in the Pipeline Defect Assessment Manual. Paper presented at International Conference on Pressure Vessel Technology, ICPVT-10, Vienna.
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9. Hereth, M., Selig, B., Leewis, K. and Zurcher, J. (2005). Develop a compendium of best practices to prevent mechanical damage to gas and liquids pipelines. GRI Report 05/0136, PRCI Catalogue No 850LN1B.
10. Hereth, M. et al. (2006, October). Leading practices for the prevention of mechanical damage. Paper 10432 presented at ASME 6th International Pipeline Conference, Calgary.
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12. Kiefner and Associates. (2000). GRI Guide for locating and using pipeline industry research. Section 9: Mechanical damage. GRI Report 00/0192 (contains a review of 60 previous reports and publications).
13. Kiefner, J.F., Mesloh, R.E., and Kiefner, B.A. (2000). Analysis of DOT reportable incidents for gas transmission and gathering system pipelines, 1985-1997 PRCI Catalogue No. L51830.
14. Leewis, K. (2006; October). The role of technology in preventing/detecting mechanical damage. Paper 10426 presented at ASME 6th International Pipeline Conference, Calgary.
15. Leis, B.N. and Hopkins, P. (2003). Review and gap analysis of remaining issues concerning mechanical damage. PRCI Catalogue No L52013 (contains a review of 180 previous reports and publications).
16. McCoy and Ironside. (2004, October). Dent management program. Paper 0393 presented at ASME 5th International Pipeline Conference, Calgary.
17. Rosenfeld, M.J. (2001). Proposed new guidelines for ASME B31.8 on assessment of dents and mechanical damage. GRI Report 01/0084.
18. Rosenfeld et al. (2002, September). New criteria in ASME B31.8 for prioritization and repair of mechanical damage. Paper 27122 presented at ASME 4th International Pipeline Conference, Calgary.
19. Warman, D. (2006, October). Management of pipeline dents and mechanical damage in gas pipelines. Paper 10407 presented at ASME 6th International Pipeline Conference, Calgary.

4 Understanding Mechanical Damage in Pipelines

4.1 Defining Mechanical Damage

This study is concerned with mechanical damage experienced by steel pipelines transporting gas and liquids for energy-related applications. In the context of the study, mechanical damage is defined as follows:

Localized damage to the pipe resulting from contact with an object.

"Localized" means that the damage is confined to some portion of the pipe cross section or that it has a limited extent along the pipe's length (for example, less than five pipe diameters).

Contact with an object results in a load or stress experienced by the pipe that has not been considered during the design of the pipeline. Such loads and stresses can be of short or long duration. The contact is usually unintentional, but may be deliberate (e.g., vandalism). Contact may occur during manufacture (excluding pipe-forming activities), transport, construction, operations, or maintenance. (Note that modifications to the pipe due to properly conducted maintenance activities are excluded, but that damage due to incorrectly conducted maintenance activities is included.) Most mechanical damage that could lead to a failure occurs as excavation damage, either by the operator or its contractor, or, more prevalently, from third-party activity over or near the pipeline.

The scope of this study, and the definition above, excludes damage that does not result from contact with an object. Excluded forms of damage include flattening and ovalization due to soil loading or settlement, buckling and wrinkling due to ground settlement, landslip, frost heave, earthquake, land erosion, mud flow, washout, and heavy equipment operating over the buried pipe. Rock dents are included as mechanical damage with the study scope.

Mechanical damage cannot be typified as a singular condition. The damage introduced by various kinds of equipment or particular circumstances may result in a broad range of impacts to the pipe. The physical attributes of the damage itself – length, depth, width, orientation, and surface appearance – can vary greatly. As with any defect, the severity of the condition is dependent on the defect geometry, the properties of the pipe steel, and the stress level at which the pipeline operates. Ultimately, the significance of the damage is "path dependent," meaning it is strongly affected by all of the circumstances of the damage event and the affected pipe. Many of the inciting causes of a particular occurrence of mechanical damage may be unknown because the damage event was not witnessed or reported. In addition, the effects of particular types of damage on pipeline integrity are not fully understood from a scientific standpoint.

In this section, mechanical damage is discussed in three broad categories: dents, gouges, and combined dent/gouge defects. Figure 4.1 shows examples. Each mechanical damage defect reflects a unique combination of conditions, such as the indenter size and shape, as well as force, angle, orientation, and duration of impact. The different forms of damage can be generalized to facilitate assessment and prioritization of repairs, as explained below (Cosham and Hopkins, 2002).

A. Dent

B. Gouge

C. Dent with Gouge

Figure 4.1 – Examples of Mechanical Damage Features

4.1.1 Dents

A dent is defined here as a depression which produces a gross disturbance in the curvature of the pipe wall, caused by contact with a foreign body, and resulting in plastic deformation of the pipe wall.

A dent can be further categorized as:

Smooth or Plain Dent: A dent which causes a smooth change in the curvature of the pipe wall, does not contain a stress concentrator or wall thickness reduction, and does not change the curvature of an adjacent girth weld or seam weld.

Unconstrained Dent: A dent that is free to rebound elastically (spring back) when the indenter is removed and is free to reround as the internal pressure varies.

Constrained Dent: A dent that is not free to rebound or reround, because the indenter is not removed. A rock dent is an example of a constrained dent.

Complex Dent: Any dent with a gouge, groove, scratch, stress riser, or other secondary defect or a dent that affects the curvature at a nearby weld.

The depth of a dent depends on the force of the indenting object, the diameter and wall thickness of the pipe, internal pressure, material properties, and any constraint of the pipe during deformation. Pipes of larger diameter and lower wall thickness have a higher compliance ratio, and so are able to deform more elastically under an applied force. However, if the pipeline is constrained by stiff soil, then the damage may be greater due to the thinner wall. Clearly, a pipe with lower yield strength will plastically deform sooner under applied force. If a pipeline is internally pressurized during the damage process, then the effective stiffening will act against the applied force and possibly reduce dent depth. These parameters all affect the resulting depth of indent and, therefore, the pipeline's structural integrity. (Hopkins and Leis, 2003)

4.1.2 Gouges

A gouge is defined here as surface damage to a pipeline caused by contact with a foreign object that has moved or removed material from the pipe, resulting in metal loss, metal movement, microstructure damage, crack, and/or other detrimental feature created during the damage process.

Gouges are typically formed when an object such as an excavator tooth is drawn across the surface of the pipe. The gouge acts as a stress concentrator which affects structural integrity. In addition, the gouge typically results in metallurgical damage in the form of strain hardening of the material and residual stress. These features differentiate gouges from many other metal loss defects, such as corrosion, which may result in reduced wall thickness of the pipe but do not involve metallurgical damage. The length and orientation of a gouge, as well as other characteristics, can vary significantly at a mechanical damage location, as shown in Figure 4.2.

Figure 4.2 – Gouge Characteristics

4.1.3 Combined Defects

When dents and gouges are found together, containing cracks or damaged metal, or when one or both are near a seam or girth weld, the damage should be treated with caution. Complex mechanical damage is not easy to evaluate, nor are the simple "rules of thumb" discussed later in this report applicable.

4.2 Mechanical Damage Features and Characteristics

Mechanical damage can degrade or reduce the serviceability (ability to function as designed) of a pipeline. In order to understand and evaluate the severity and structural implications of mechanical damage, it is first necessary to identify the features associated with damage, to categorize them and, where appropriate, to measure them. Many features or characteristics can affect the severity of damage. These features may include one, several, or all of the following:

Changes in pipe shape.

- A localized dent, change in curvature in the circumferential direction, and/or change in straightness along the pipe axis.
- Ovalization of the cross section near or at positions removed from the point of contact or area of most significant indentation.

Changes in wall thickness.

- Removed metal due to cutting, gouging, scraping, plowing or similar mechanisms.
- Thinning due to stretching, usually in a sharp dent or near a scrape, gouge, or similar anomaly.
- Increases in wall thickness, as sometimes occurs where an indenter "pushes" material to the side as it moves along the pipe.
- Re-deposited metal, as sometimes occurs when an indenter rides up and over metal that has been cut or scraped off during damage.

Changes in localized stresses and strains.

- Residual stresses and strains. Stress and strain fields have axial, circumferential, and radial components. The local stresses and strains are "path dependent," which means they are influenced by the order and magnitude of loads and deformations.
- Stress concentrations at, for example, the corners of a gouge.
- Other increases or decreases in stresses due to changes in shape.
- Re-rounding, created when an indenting object is removed from a pressurized pipe.

Changes of material properties.

- Modification of mechanical (and magnetic) properties of the pipe material due to plastic strain. Strain hardening may increase yield strength, reduce ductility (i.e., tensile elongation), and/or affect toughness. These changes can range from modest, in areas where the local strains are the same order of magnitude as yield strains, to extreme, immediately under a sliding indenter.
- Changes due to phase transformations resulting from rapid heating and cooling.

Other anomalies or defects.

- Surface cracks that formed either at the inside surface during denting, or at the outside surface during re-rounding. Re-rounding cracks are often angled on a plane at 45° to the radial direction and/or "Z-shaped."
- Microvoids and buried cracks, especially in the deformed subsurface layer.
- Extension of cracks or microcracks by subsequent fatigue, corrosion fatigue, or stable crack growth.
- Environmental cracking, such as superficial stress corrosion cracking (SCC)
- Local or generalized corrosion, sometimes related to shielding by damaged coating and/or the presence of rocks immediately adjacent to the pipe wall.
- Other defects or anomalies, such as latent defects in an adjacent strain-sensitive seam or girth weld.

The following paragraphs provide more detail on some of the factors listed above: re-rounding and elastic springback, localized stress/strain fields, and reductions in toughness brought on by the damage process.

4.2.1 Elastic Spring-Back and Re-Rounding

The process of introducing a dent into a pipeline involves both elastic and plastic deformation. When the indenter is removed, the dent will "spring back" to some degree due to the stored elastic energy being released. The spring-back phenomenon is also referred to as "elastic rebound." Elastic distortions or flexing may occur when the pressure is increased or decreased at a dent.

Because the pipeline is pressurized during the deformation, or if the pipeline is subsequently re-pressurized during a return to service or pressurized above the level present when the damage was formed, the internal pressure will also reduce the dent depth via a process referred to as "re-rounding." In this report, re-rounding refers to plastic or permanent distortion in and around a dent due to internal pressure. Often, the effects of re-rounding due to internal pressure are greater than those due to the elastic response.

Spring-back and re-rounding behavior depend on pipe geometry, material properties, operating pressure, the pipeline's external support stiffness, and dent shape. Typically, a long dent will spring back and re-round more readily than a short dent, and recovery occurs more towards the middle of the dent than at the ends. Spring back and re-rounding is greater in thin-walled pipes than in thick-walled pipes, due to higher geometric compliance. Pipes operating at higher pressures will exhibit more re-rounding due to the higher driving force to re-round.

4.2.2 Stress/Strain Fields [Hopkins and Leis (2003)]

The initial indentation of a pipe leads to tension in the pipe's internal surface and compression of its external surface. The material yields locally, causing a plastic strain on both surfaces. When the indenter is removed and the pipe re-rounds, the external surface experiences residual tension. If the residual tension is severe enough, cracking may initiate. In many cases, cracking may lead to immediate failure of the pipe during the re-rounding process.

In some circumstances, the dent is prevented from re-rounding due to constraint of the pipe material. If damage is caused when the pipeline is laid against a rock, or ground movement leads to the pipeline being pressed against a fixed object, the dent is "constrained" against elastic rebound and re-rounding. If damage is caused by mechanized equipment and the indenting object is removed during the damage event, then the dent is typically "unconstrained" against elastic rebound and re-rounding. The re-rounding process leads to significant changes in localized stress/strain fields, and may lead to cracking.

Denting and re-rounding processes are associated with plastic deformation of the pipe material. The plastic strain incurred in the material during the damaging process may reduce the toughness or remaining ductility of the material. This strain is superimposed on any mechanical strain introduced during pipe manufacture and pipeline installation. The final stress and strain state near a dent and gouge depends on the strain history. It is triaxial in nature, though this depends on the specific details of the denting process. (ANSI/ASME B31.8S, 2004)

4.2.3 Reduction of Toughness and Ductility Due to Strain

The deformation associated with mechanical damage can overload (greater than Ultimate Tensile Strength) and significantly affect the properties of the pipe material. When a gouge is formed, the area immediately beneath the indenter is highly deformed and its crack-initiation resistance significantly reduced. This type of damage extends into the pipe material to a shallow depth. The deformed layer is usually harder than the base metal and may contain transformed microstructures resulting from rapid heating and cooling during its formation.

In addition, the denting process may strain-harden the material away from the location that was contacted by the indenter. Strain-hardening or cold work during plastic deformation can increase hardness and decrease toughness, but to a lesser extent than under the indenter. The effects of prior strain on mechanical properties, particularly toughness, have been reviewed by Leis and Hopkins (2003).

Few experimental studies have addressed reductions in the material properties issue; the results appear to indicate that crack initiation resistance reduces rapidly, falling to about half the initial value on reaching 10 percent prior strain, but that the tearing resistance remains unchanged. Other researchers (Cosham et al., 2004; Swankie, Martin, and Andrews, 2005) have shown that tensile ductility is also reduced by prior strain, but not to the same extent as for fracture initiation. However, there appear to be significant variations among different pipe materials, linked to the original toughness and ductility of the unstrained material.

Mechanical damage can also affect the magnetic properties of the material. Changes in magnetic properties affect the magnetic in-line inspection results. See Nestleroth and Crouch, 1998[1]

The effects of prior strain in reducing the properties of the material surrounding the dent have been incorporated in some of the models of time-dependent failure, as will be seen later in Section 7.

4.3 Geometry and Characterization of Damage

Dent depth is usually measured by reference to the original outside contour of the undamaged pipe, and often expressed as a percentage of the original pipe diameter. Dent shape can be defined in terms of the local radius of curvature in the circumferential and/or axial direction. (Figure 4.3) Distinction is made between whether the measurement is obtained when the pipe is pressurized or depressurized. This will be discussed further below. Such measurements include a degree of ovality or flattening of the pipe surface as an unavoidable component of depth.

Dent length, width, or size may be defined by the envelope within which the radius of the damaged pipe is different than that of the undamaged pipe, but this is sometimes difficult to determine. Dent size has also been defined in terms of the locus of points of half-depth (API 1156, 1997; EPRG, 1999; Rosenfeld, Pepper, and Leewis, 2002; Ironside and Carroll, 2002; Dinovitzer et al., 2002; Hopkins and Leis, 2003; Baker, Jr., M., 2004)

[1] Nestleroth, J. B. and Crouch, A. E., “Variation of Magnetic Properties in Pipeline Steels,” Interim Report to the DOT under Contract No. DTRS56-96-C-0010, March 1998.

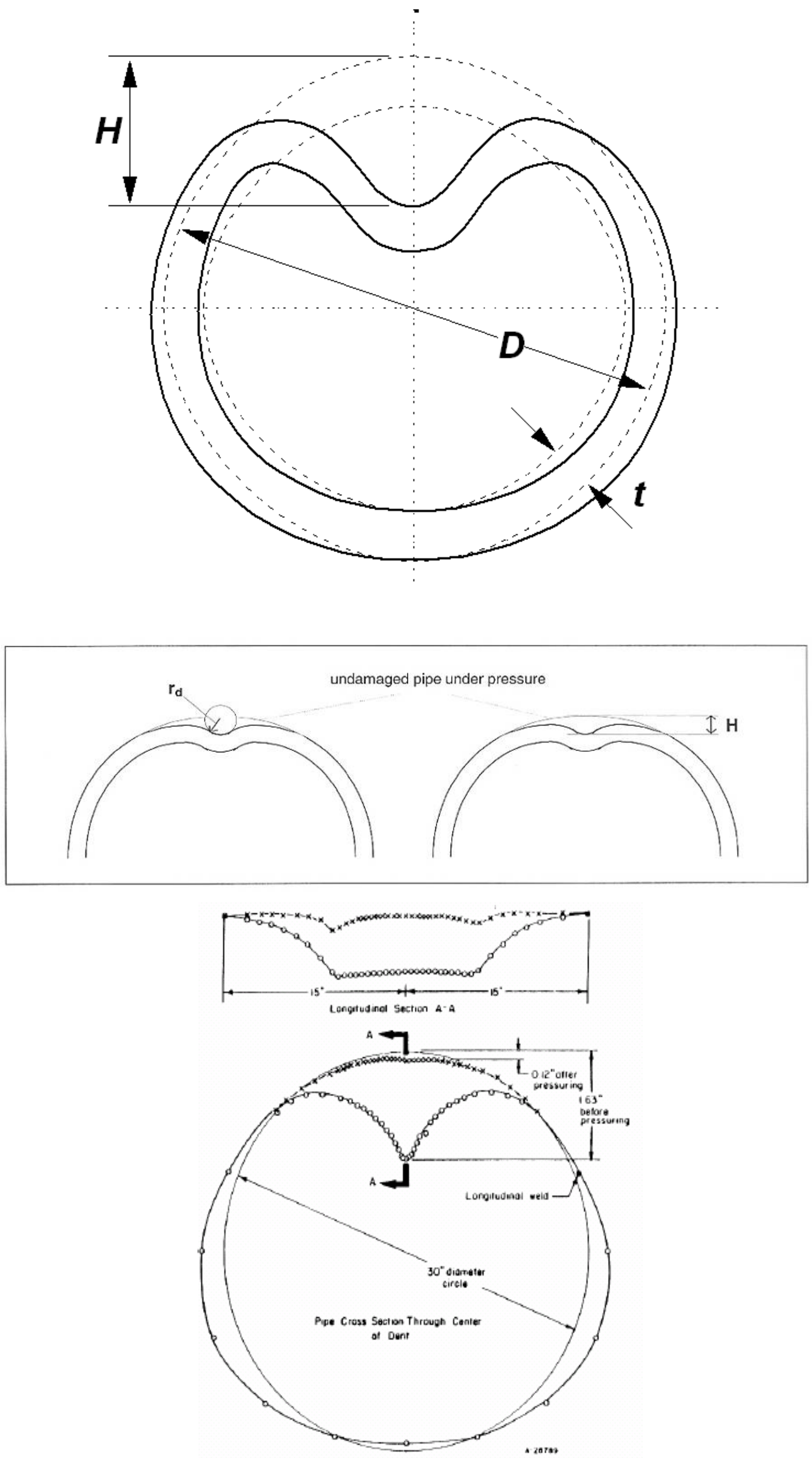

Figure 4.3 – Dent Depth Measurement (Hopkins and Leis, 2003)

Dents can be described as either non-reentrant or reentrant (Figure 4.4). A positive radius value defines a non-reentrant dent, in which the outer surface of the pipe is flattened but retains its convexity. A negative radius value defines a reentrant dent, in which the outer surface of the pipe is dented deeply enough that it becomes concave. Dent shape has also been described in terms of the maximum angle subtended by the flanks of the dent (Baker, 2004)

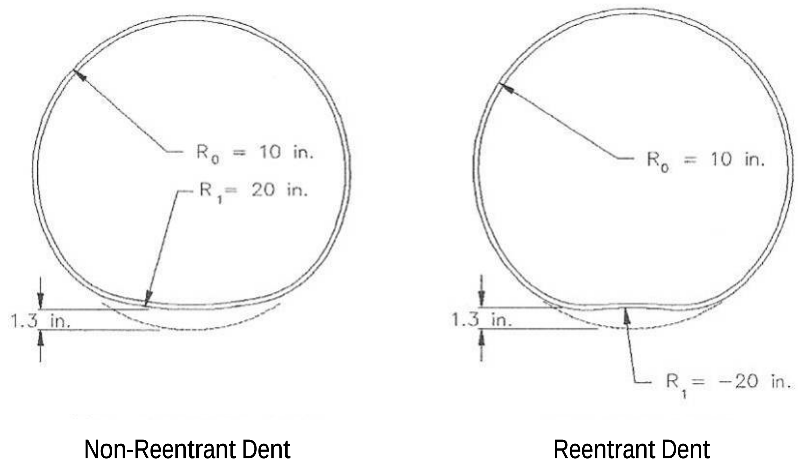

Figure 4.4 – Measurement of Re-Entrant and Non-Re-Entrant Dent Depth (Baker, Jr., M., 2004)

The geometric parameters used to characterize a gouge are the depth, length, width, and angle to axis, etc. These are usually measured from the undeformed outer radius of the pipe (Figure 4.5).

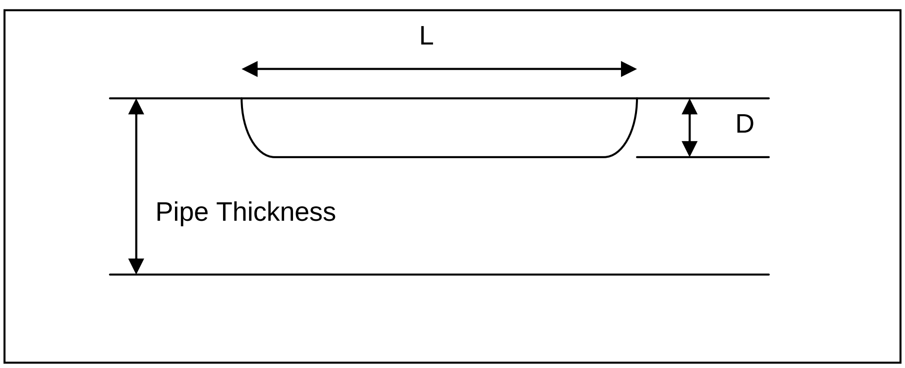

Figure 4.5 – Gouge Depth Measurement (OPS TTO10, 2004)

For combined dents and gouges, the gouge length and depth are usually measured from the metal surface at the shoulder of the gouge – that is, not including the depth or length of the dent (Figure 4.6). Similarly, the depths of cracks are measured from the metal surface, excluding the depth or length of the associated dent and/or gouge. However, for assessment purposes, it sometimes may be appropriate to add the gouge and crack depths (see Section 7).

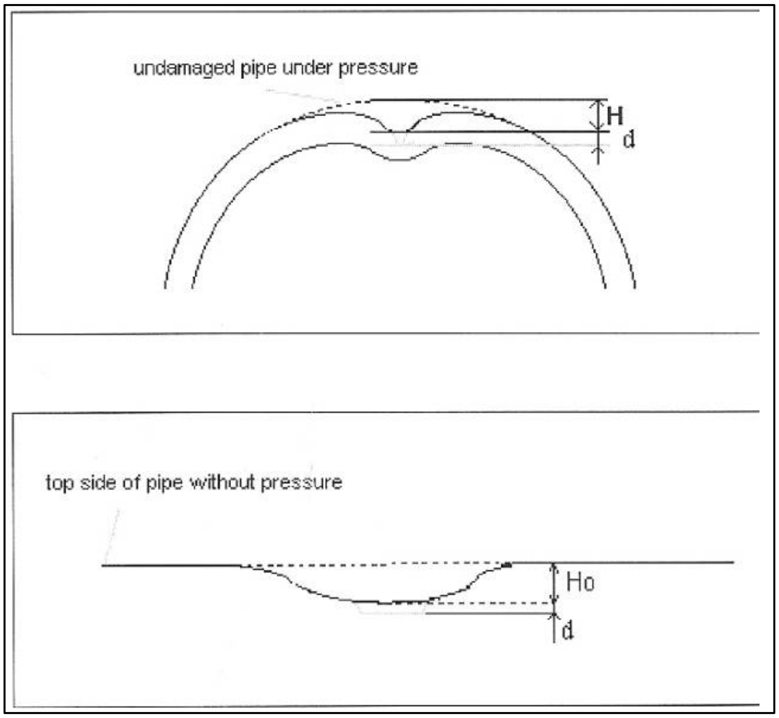

Figure 4.6 – Depth Measurement for Combined Dents and Gouges

The locations of other secondary features associated with mechanical damage (including corrosion, SCC, and welds) are usually defined by measuring the axial and/or circumferential separations of the deepest point of the dent/gouge and the deepest/midpoint of the secondary feature.

The location of damage is usually referenced to the circumferential orientation and to the girth weld immediately upstream. Additional characterization in the ditch is explained in Chapter 6.

4.4 Repair Conditions and Failure Modes

The operating conditions of the pipeline and the ductility of the pipe material have profound effects on the impact of damage to a pipeline. Mechanical damage poses a range of possible threat to the integrity of an affected pipeline, ranging from dire and urgent, to tolerable today but only for some limited period of time, to benign. The types of damage of interest to this study are those resulting from damage events that do not puncture the pipeline, but result in damage features found by an ILI run that require assessment of current and future integrity before excavation.

In effect, all forms of mechanical damage, as defined for purposes of this report in Section 4.2, that do not cause immediate failure of the pipe are potential delayed failures. Mechanical damage which does not fail right away may someday fail, for example, due to the effects of several possible mechanisms:

- The damage may fail at a higher pipeline pressure than the pressure within the pipeline at the time of the damage event, or than what is normally present during a normal pressure rise or surge condition;
- The damage may fail as a result of accumulation of local plastic strain and exhaustion of ductility in the damage zone, due to shakedown[1], creep, and low-cycle fatigue;

[1] Although the residual dent depth of a "rerounded" dent is usually very shallow, tests have shown that the dent never fully rerounds, which means that it continues to fluctuate in and out with changes in operating pressure. It can

- The damage may fail from high-cycle fatigue crack growth caused by the effects of many pressure cycles acting over time on the residual deformation and stress concentrator.
- The damage may serve as a site for the initiation of corrosion or SCC.

To overcome these threats, pipeline assessment and the mitigation or repair must be carried out. The need for repair can be categorized as "immediate" or "delayed." The critical distinction between the immediate and delayed pipeline repair categories is in the urgency of the response as dictated by the current factor of safety above the pipeline's operating pressure and the anticipated time to failure. Times to failure may range from a few weeks or months (warranting an immediate response), to years, decades, or possibly never.

4.4.1 Immediate Repair Conditions

The Immediate Repair category includes damage sufficiently severe that the pipe is thought to be unsafe to operate at the current pressure level. So even though the pipeline is currently holding pressure, the presumption is that the factor of safety is inadequate and a delayed failure could occur at any time. This category may also include damage that is insufficiently characterized to determine whether the pipe can operate safely at the current pressure level.

Such urgent conditions require that the operator respond immediately to investigate and act to restore the margin of safety of the pipeline. Response options could include shutting down the pipeline, reducing the pressure of the pipeline by some significant amount so as to provide a known minimum factor of safety, or performing a repair capable of effectively restoring the strength of the pipe. (ANSI/ASME B31.8S, 2004)

Current integrity management planning standards such as ASME B31.8S, 49 CFR Part 192 Subpart O, and 49 CFR Part 195.452 consider that any combination of indentation with a gouge poses an immediate threat. A principal reason for this is that such damage has been known to fail at operating stress levels. In addition, there is no simple, straightforward method an operator can use to accurately calculate the safe operating pressure (in other words, there is no "B31G" for dents) or the time to failure. Involved analytic methods derived from research are used by experts to obtain estimated times to failure. The methodologies are covered in more detail in Section 7. (ANSI/ASME B31.8S, 2004; PHMSA, 2008)

4.4.2 Delayed (or Scheduled) Repair Conditions (ANSI/ASME B31.8S, 2004)

The Delayed Repair category includes all forms of damage not deemed to be severe enough to fall into the immediate threat category and not otherwise shown to be tolerable. The length of the predicted time to failure is sufficiently long to afford opportunities to monitor the pipeline condition and/or schedule the investigation and make the decision to repair the damage.

A dent with a minor scrape or gouge need not impair the safety of the pipeline, and the pipeline's remaining life can be many years. This is particularly true where the pipeline operates at a moderate or low stress level and experiences only infrequent pressure changes. It may be true for slight damage in a pipeline that operates at higher stresses. However, the possibility of minor or non-threatening mechanical damage is not yet recognized by integrity management planning standards or regulations. Current integrity management planning standards generally consider only plain deformations containing no scrapes, gouges, or cracks to qualify as delayed repair conditions if they do not exceed the allowable strain limit.

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take many cycles of pressure for the dent to "shake down" to elastic action, which means that plastic strain can continue to accumulate in the damaged area. If the damage survives shakedown, the dent will subsequently cycle elastically over a smaller range of motion, providing a mechanism for continued crack growth by fatigue in service. (Rosenfeld, 2002)

4.4.3 Growth of Cracking from Mechanical Damage

Hopkins and Leis (2003) describe the growth of cracking from mechanical damage as driven by two forces:

- The over load plastic strain tension at the inside surface of the pipe during contact with the indenter. If sufficient, it can lead to cracking or plastic collapse of the remaining pipe wall and possibly to immediate failure.
- The tension at the outside surface of the pipe as the indenter is removed and the pipe re-rounds. Again, if this plastic strain magnitude is sufficient, it can lead to immediate failure.

Cracking at the outside surface of the pipe may also be promoted by the presence of microcracks generated during sliding contact with the indenter. As mentioned earlier, high plastic strains incurred during deformation increase the hardness and reduce the toughness, sometimes to the extent that cracks or microcracks develop along the internal or external surface as the pipe deforms. These cracks are often oriented perpendicularly to the motion of the indenter and penetrate at a 45° angle to the pipe surface.

Cracking can develop further as a result of stable tearing, fatigue, environmental stresses, cyclic-stress-activated low temperature creep, and/or as a result of other delta strain mechanisms. Thus, dents and gouges can show both time-dependent and pressure-cycle-dependent crack development. These phenomena may diminish as the local stresses redistribute and/or the steel strain hardens sufficiently to blunt the damage, but may nevertheless continue until delayed failure occurs. In-service failures have occurred at any time from a few days to tens of years after the damage event.

Features associated with high-cycle fatigue are more often seen in oil or hazardous liquid product pipelines than in natural gas pipelines. The more severe fatigue experienced by liquid pipelines is attributed to higher frequency load fluctuations. This condition is also exacerbated by the larger stress cycles and higher rates of stress change than seen in natural gas pipelines.

4.4.4 Leak versus Rupture

A mechanical damage defect can fail as a leak or a rupture. In a leak, the full-penetration crack length is similar to that of the initial damage feature, and the release is controlled or limited by the opening size. In a rupture, the initial opening extends or grows rapidly along the pipe axis due to crack propagation at one or both ends. The critical flaw size, which is the length at which the failure mode changes from leak to rupture, depends upon the geometry of the pipe, the length of the fully penetrating defect, the pipe properties, the operating stress level, and other factors.

Determination of the boundaries that discriminate between leak and rupture behavior is similar to that for other axial defects, except that there may be additional stresses associated with the geometry of the damage, and the material in the immediate vicinity may exhibit reduced toughness. For both these reasons, rupture may be more likely at the point of mechanical damage than at the site of equivalent length corrosion defects or axial cracks. Such considerations influence the consequences of mechanical damage and the priority for repairs.

4.5 Failure Statistics

Data concerning pipeline failures have been collected by pipeline safety agencies in the United States, Canada, and Europe. The data have been periodically analyzed to identify trends with respect to causes of failure and particular risk factors. The analyses have generally indicated that mechanical damage is an important cause of pipeline failure. In the past, mechanical damage caused by encroachment activities (also known as third-party damage) was the leading cause of significant incidents in the United States.

Owing to the advent and widespread adoption of convenient one-call systems enabling contractors and others to have pipelines located and marked prior to excavation, the proportion of significant incidents has gradually decreased in recent years such that third-party damage is still a major cause but not the single greatest cause. Since 2000, the corrosion category has become the largest causation category annually, but excavation damage remains the largest for all years since 1985 in aggregate. As previously illustrated in Table 1.1, excavation damage also remains one of the largest causation categories for deaths and serious injuries. (PHMSA, 2008)

4.5.1 U.S. Industry Experience (PHMSA, 2008)

Data provided by the Pipeline and Hazardous Materials Safety Administration (PHMSA) indicate that mechanical damage in the form of excavation damage constitutes a substantial proportion of all significant incidents on pipeline systems. Mechanical damage due to outside forces not associated with excavation, such as vehicle contact or vandalism, is also a factor, but the percentage of these incidents is very small in comparison with that for excavation damage. Since 2003, PHMSA began to report on these types of damages separately in a cause category entitled "Other Outside Force Damage." For the period from 1988 to 2008, 1,563 incidents were reported as being caused by excavation damage on all PHMSA regulated pipeline systems, including gathering, distribution, and transmission, both onshore and offshore[1]. This accounts for 25.9 percent of all significant incidents and 13.6 percent of all property damage. There is a comparable proportion of significant incidents attributed to excavation damage for both hazardous liquid and gas transmission pipelines.

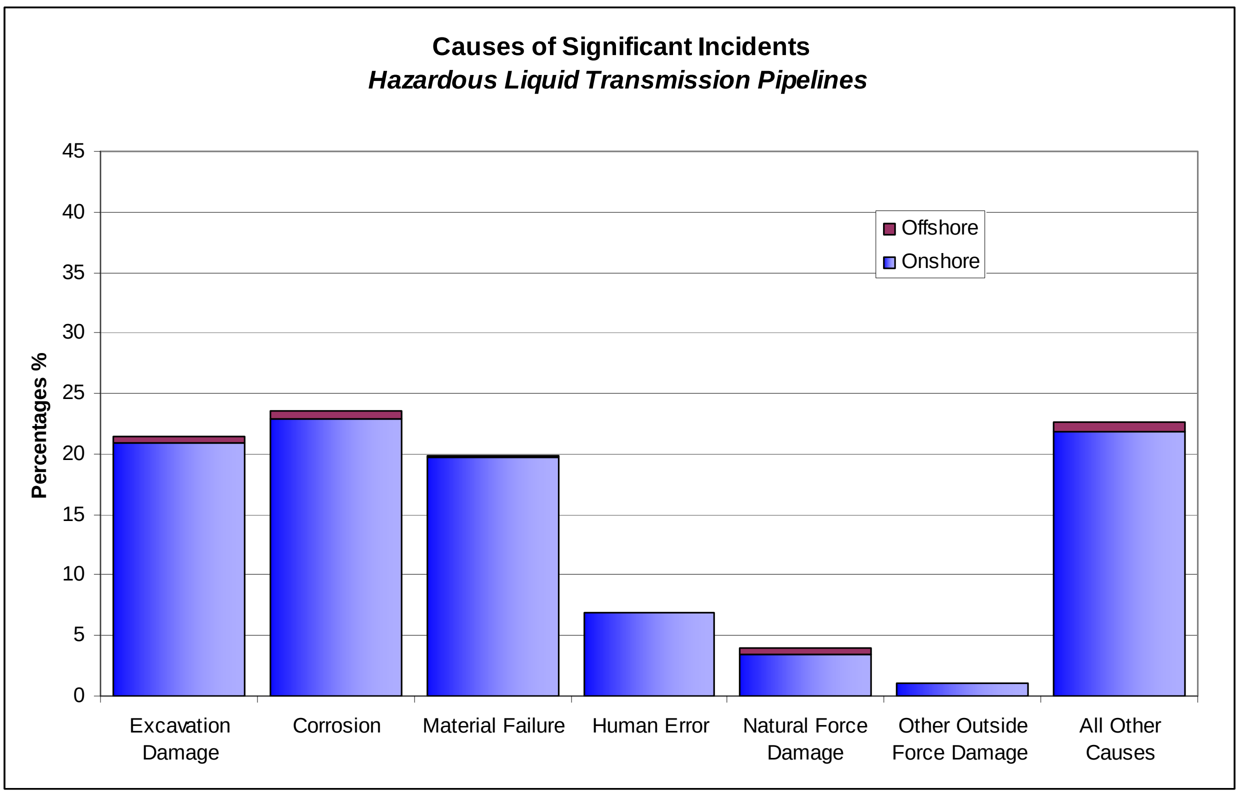

Figure 4.7 – Causes of Significant Pipeline Incidents on Hazardous Liquid Transmission Pipelines from 1988-2008
Source: DOT/PHMSA Pipeline Incident Data

[1] PHMSA statistics given for transmission pipelines include all PHMSA-regulated pipelines, including onshore and offshore, unless otherwise indicated.

Figure 4.7 shows the breakdown of significant pipeline incidents by cause for hazardous liquid transmission pipelines for the period 1988-2008. During this period, there were 43 fatalities reported and 234 injuries requiring hospitalization, all on onshore pipelines. Of these, 14, or 33 percent of fatalities, and 87, or 37 percent of inquiries, were the result of excavation damage. Only by a slightly larger percentage were fatalities and injuries attributed to “all other causes.” This category includes those incidents whose causes could not be specifically determined. Total property damage costs in excess of \$1.54 billion were reported for all liquid pipeline incidents, with 14 percent, or \$223 million, resulting from excavation damage. Eighty-five percent of the excavation damage property cost was to onshore pipelines.

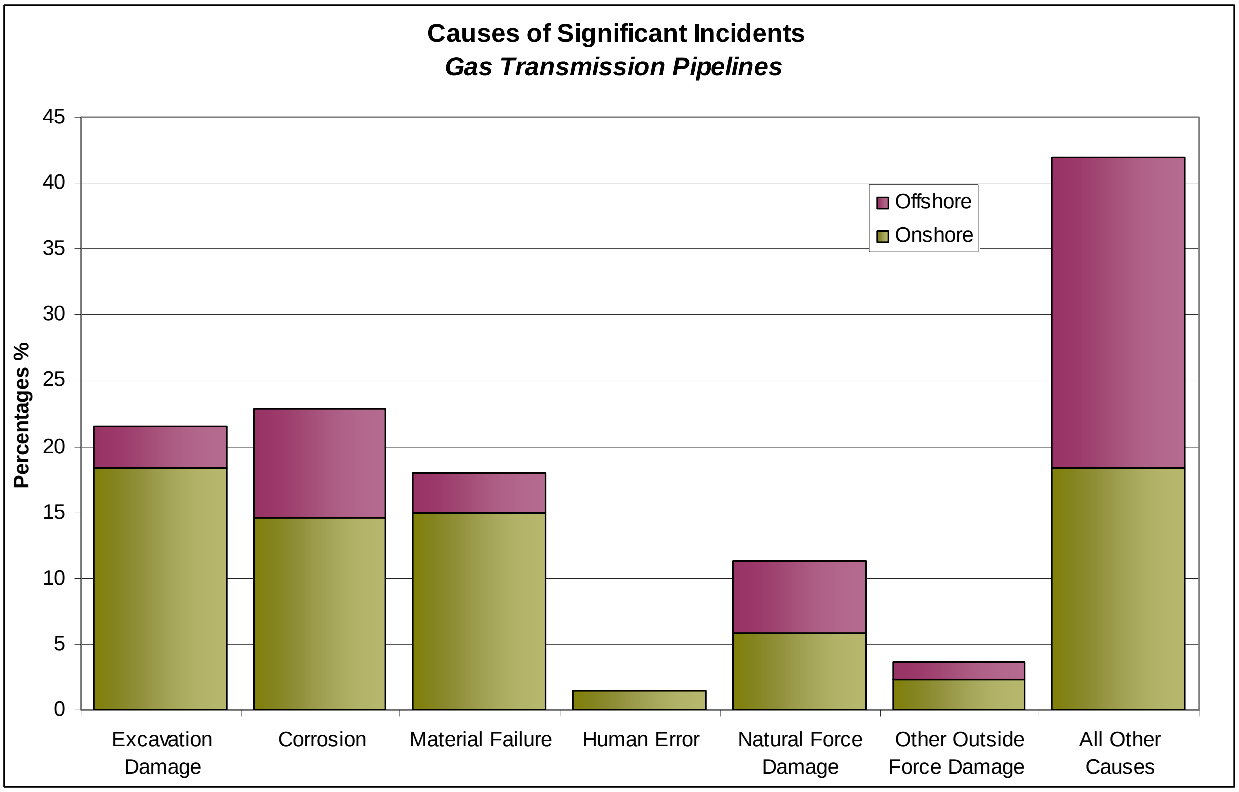

Figure 4.8- Causes of Significant Pipeline Incidents on Gas Transmission Pipelines from 1988-2008
Source: DOT/PHMSA Pipeline Incident Data

A similar breakdown is shown in Figure 4.8 for natural gas transmission pipelines from PHMSA data from 1988-2008. There were 36 fatalities and 76 injuries reported resulting from excavation damage, 61 percent and 36 percent, respectively, of the total deaths and injuries due to all causes. One-half of the excavation damage-related deaths were associated with onshore pipelines, along with 74 percent of the injuries. Total property damage of \$958 million was reported as associated with all causes, with 12 percent attributed to excavation damage. Seventy percent of the excavation-related property damage was associated with onshore pipelines.

Data for gas distribution pipelines is shown in Figure 4.9 for comparative purposes. While the scope of this report relates primarily to mechanical damage in transmission pipelines because of the report’s emphasis on detection, characterization, and assessment issues, the presentation of PHMSA data on gas distribution pipelines helps to frame the context of damage prevention of pipelines in general. Due to the presence of gas distribution systems in more congested areas, the percentages of failures due to excavation damage far outweighs other cause categories. Excavation damage-related fatalities and injuries for the 1988-2008 reporting period were 97 and 459, respectively, or 30 percent and 34 percent of all fatalities and injuries. Property damage costs were 17 percent of the nearly $1 billion total costs for all gas distribution incidents.

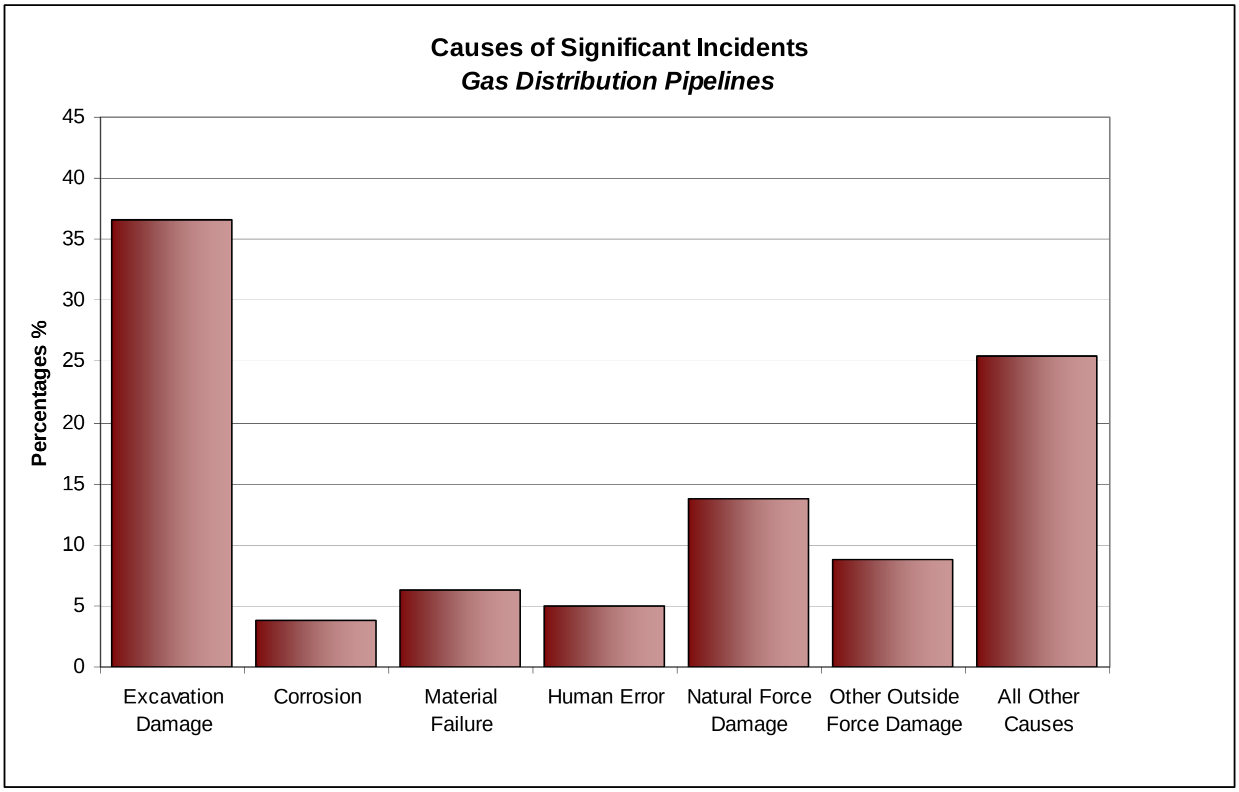

Figure 4.9 - Causes of Significant Pipeline Incidents on Gas Distribution Pipelines from 1988-2008
Source: DOT/PHMSA Pipeline Incident Data

As previously discussed and illustrated in Figure 1.2, the trend for serious pipeline incidents (those resulting in a death or in patient hospitalization) has continued to decline. This positive performance is reinforced by information in the 2007 Common Ground Alliance (CGA) Damage Information Reporting Tool (DIRT) Analysis and Recommendations Report which states that there has been a "paramount reduction" in the number of underground damages (on facilities of all types) over previous years. The report attributes the reduction in underground damage incidents to stakeholder support and promotion of the new "811" one-call number, Regional CGA efforts, and implementation of CGA Best Practices by stakeholders, as well as the use of new and proven technologies, all of which are discussed in Section 5. The report states that the reduction is supported by several different sources showing downward trends, including the recognition of a slowing economy. (CGA, 2008)

4.5.2 Experience Outside the United States

Pipeline industry regulatory or representative groups in other nations, including Canada and European countries, track occurrences of pipeline incidents individually and in the aggregate. As might be expected, the criteria for reporting or recording incidents differ among the national interest groups, and this complicates detailed comparisons across all incident databases. In addition, the requirements for reporting vary in different years as regulatory requirements change. However, if incidents are lumped into a few relatively broad categories, it is possible to compare relative rates of occurrence.

Figure 4.10 shows that the primary cause of ruptures on pipelines regulated by Canada's National Energy Board (NEB) between 1991 and 2006 was cracking, followed by metal loss. Cracking includes hydrogen-induced and mechanical damage delayed cracking, stress corrosion, and corrosion fatigue. Metal loss includes both internal and external corrosion. The category of "Other Causes" includes improper operation, fire, and yet-to-be-determined causes. The NEB defines a rupture for natural gas pipelines as any unintended or uncontrolled release of natural gas, and as any unintended or uncontrolled release of liquid hydrocarbons associated with pipe body failure and a release volume in excess of 1.5 cubic meters. It should be noted that the total number of ruptures reported during this time period was 30, with only one rupture attributed to external interference. The low number of ruptures due to excavation damage has been primarily attributed to the remoteness of most NEB-regulated pipelines. (NEB, 2008)

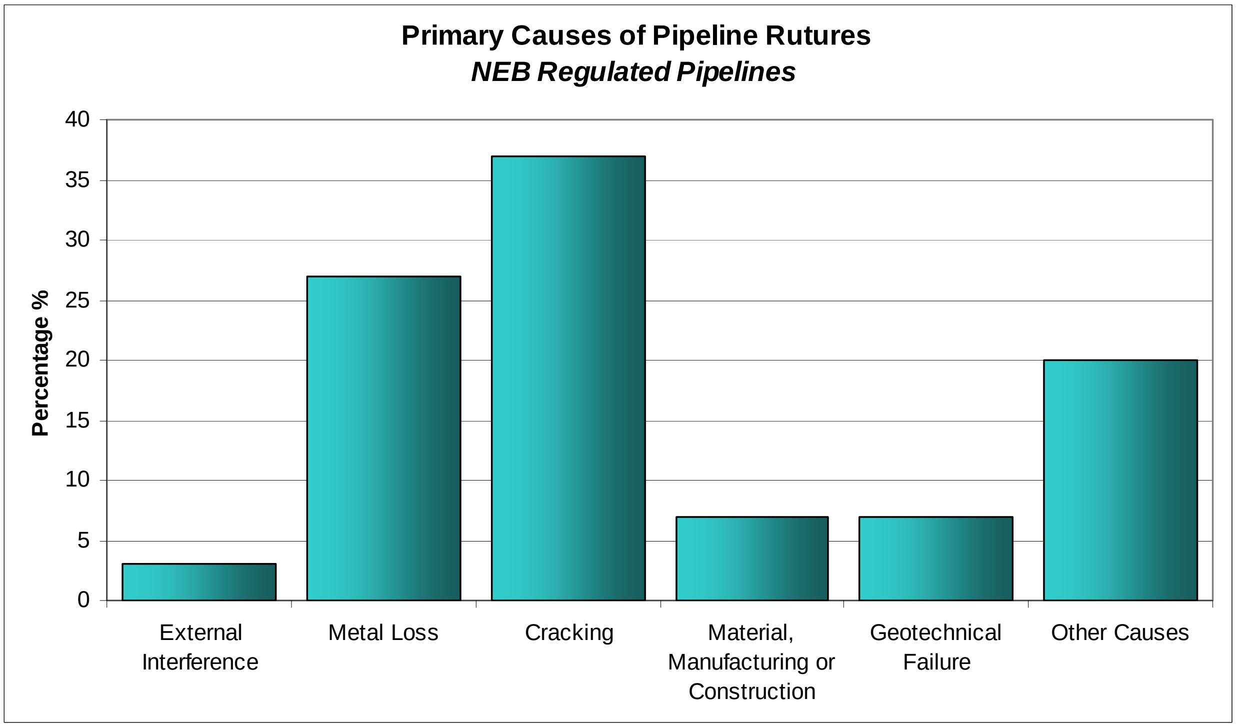

Figure 4.10 – Primary Causes of Pipeline Ruptures on NEB Regulated Pipeline (NEB, 2008)

Figure 4.11 presents data for European gas transmission pipeline incidents reported by the European Gas Incident Group (EGIG), representing 15 European pipeline operating systems. For purposes of EGIG reporting, an incident is defined as an unintended release of gas occurring on onshore steel pipelines operating in excess of 15 bar (217 psi) and located outside the fences of gate installations. It is evident that external interference is overwhelmingly the largest single cause of incidents involving gas pipelines, accounting for almost half of all reported incidents. By comparison, construction defects and material failure account for 16.5 percent and corrosion accounts for 15.4 percent of all reported incidents, respectively. (EGIG, 2008)

European data demonstrates that, while the overall proportion of external interference damage to pipelines is high, the frequency of incidents has been declining since 1970. Figure 4.12 shows that the frequency of reported incidents has declined from approximately 0.55 per 1000 /km/year in 1970 to 0.18 per 1000 /km/year in 2007.

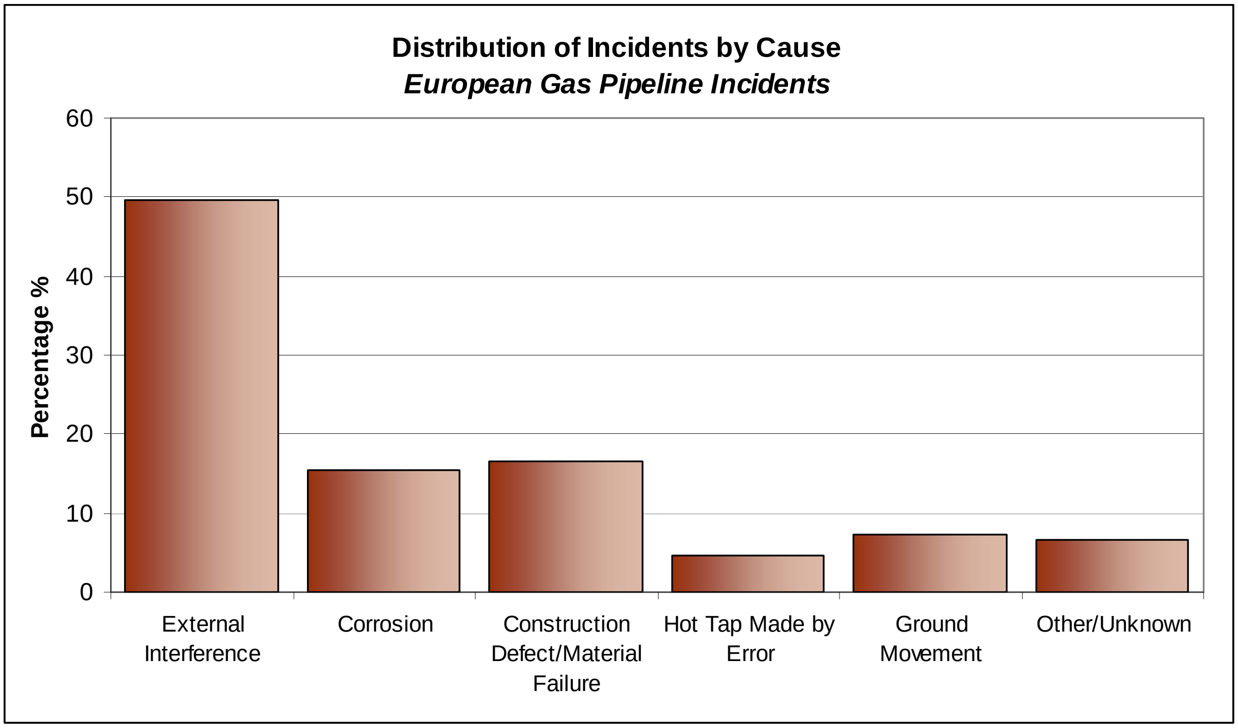

Figure 4.11 – Distribution of Incidents by Cause
(7th EGIG Report 1970-2007, Doc. No. EGIG 08.TV-B.0502, December 2008)

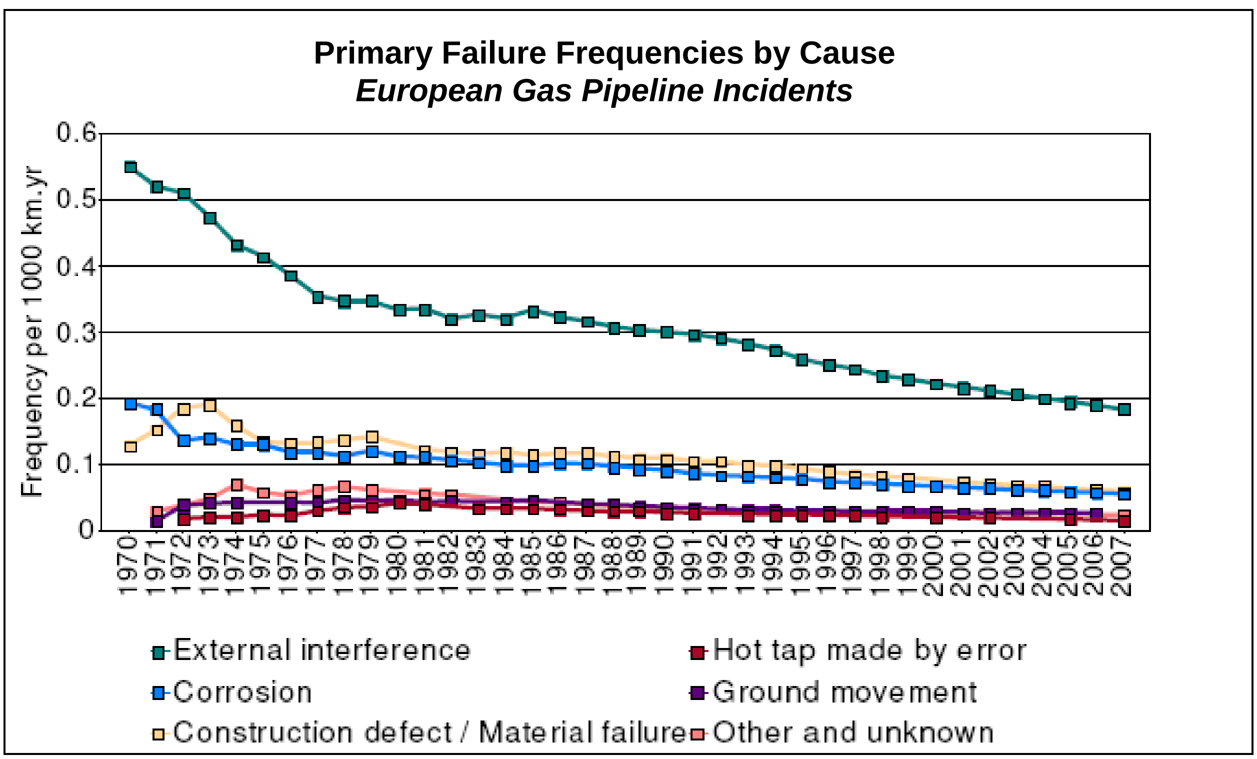

Figure 4.12– Primary Failure Frequencies by Cause - (1970-2007) The 7th EGIG Report 1970-2007, Doc. No. EGIG 08.TV-B.0502, December 2008)

4.5.3 Comparative Statistics

Figure 4.13 shows the comparison of Canada's NEB-regulated pipeline ruptures since 1991 by cause to those reported by the Energy Resources Conservation Board (ERCB) (formerly the Alberta Energy and Utility Board [EUB]), EGIG, and PHMSA. Table 4.1 clarifies the definition of "rupture" for purposes of comparison. Note that the requirements for reporting vary, and there may be some differences in terminology. While each organization reports different time frames over which rupture causes are examined, the results suggest that the leading cause of ruptures generally remains constant over time.

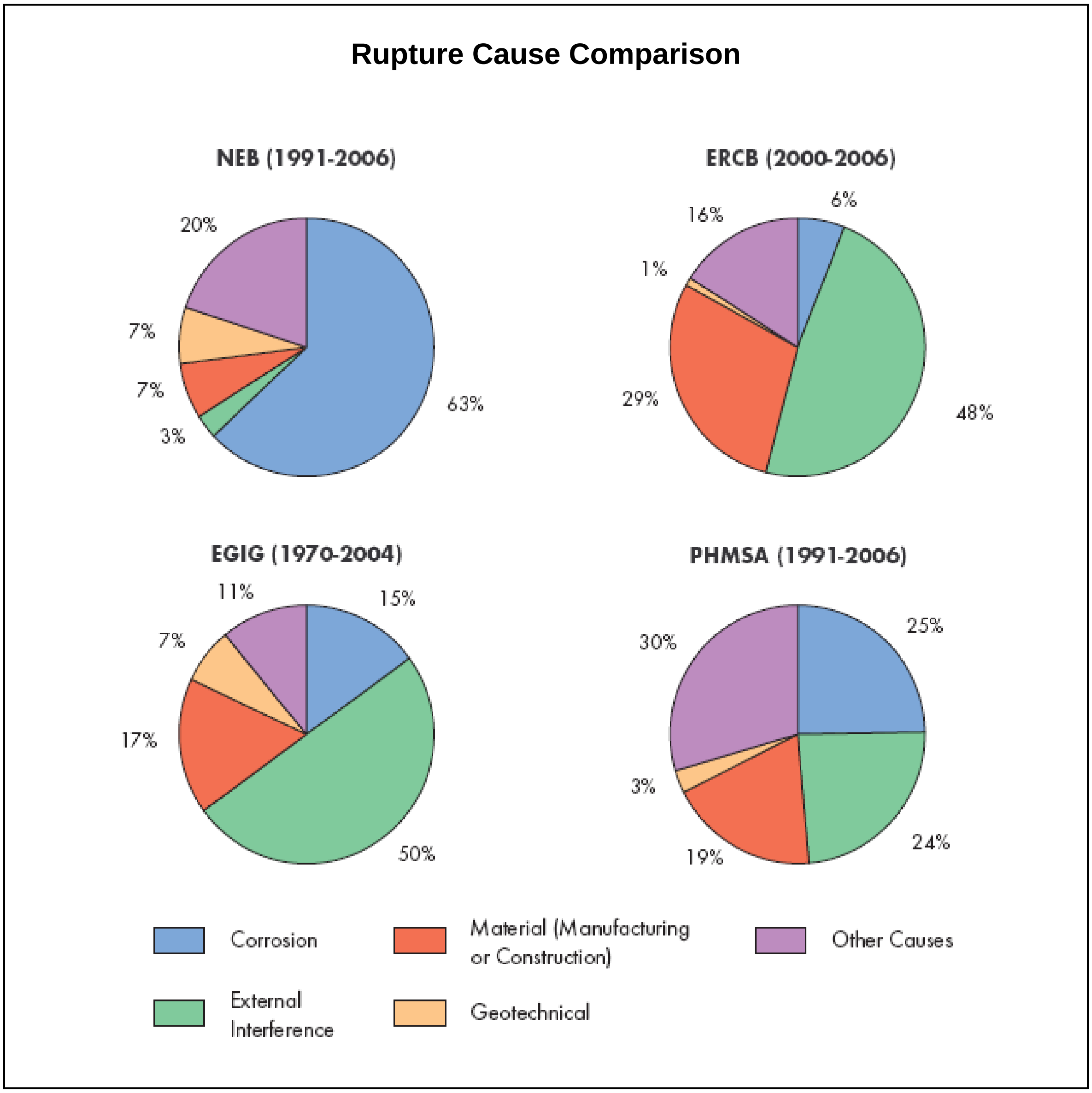

Figure 4.13 – Comparison of Pipeline Ruptures by Cause (National Energy Board, 2008)

Table 4.1 Comparison of Reporting Criteria for Pipeline Ruptures (National Energy Board, 2008)		
Source	Reporting Requirement	Pipeline Type
NEB	Rupture: “Loss of containment even that immediately impairs the operation of the pipeline” (per CSA Z662-3, Annex H).	NEB-regulated natural gas and liquid hydrocarbon
ERCB	When a leak or break occurs in a pipeline, the licensee shall immediately cause the Board to be informed of the location of the leak or break. “Break” means a rupture in any part of a pipeline and “leak” means the escapes of substance from a pipeline.	Natural gas and hazardous liquid
PHMSA	Incident : Gas releases that were associated with a death or personal injury requiring hospitalization, or a total cost of $50,000 or more Loss of 8 or more cubic meters of hazardous liquids or where property damage costs exceed $50,000. After February 7, 2002, a release of 5 gallons (19 liters) or more.	Gas and hazardous liquid transmission
EGIG	Incidents include any unintentional release of gas which occurs on an onshore pipeline operating at greater than 1500kPa outside of the fenced boundaries of installations and excluding all components except the pipe.	Gas transmission

The leading cause of ruptures on NEB-regulated pipelines is corrosion, which includes both cracking and metal loss. In contrast, PHMSA data provided for gas and liquid transmission pipelines indicates that while corrosion is a leading cause of failure, external interference (i.e., excavation damage) constitutes the second most frequent cause of failure. Both the EGIG and ERCB data indicate that external interference is the leading cause of pipeline ruptures. A major reason cited for the higher rates of external interference caused failures reported by PHMSA and EGIG is that the population densities in the U.S. and Europe are significantly greater than that of Canada. The density of the ERCB-regulated pipeline network coupled with the high levels of construction in the Alberta oil and gas sector may account for the higher external interference rates in Alberta. In any case, the ERCB data is consistent with the U.S. and European trends, and suggests that encroachment is either the largest individual integrity threat or on a par with corrosion as an integrity threat. (NEB, 2008)

4.6 Summary

Mechanical damage is often complicated and cannot be typified as a singular condition. As a result, the extent and severity of damage can vary greatly. As with any defect, the severity depends on defect geometry, properties of the pipe steel, stress level at which the pipeline operates, and other factors.

Mechanical damage can degrade or reduce the ability of a pipeline to function as designed. This chapter provides an overview of the structural implications of mechanical damage and features typically associated with dents and gouges. It summarizes the differences between immediate and delayed repair condition, and it introduces the factors that affect the failure mode (leak versus rupture). Analytic methods for use in excavation are covered in Chapter 7, rather than within this chapter. Finally, this chapter summarizes and compares data regarding mechanical damage in North America and elsewhere. Experience in the United States is consistent with that seen elsewhere.

4.7 References

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5 Prevention

5.1 Overview

Mechanical damage can result from a number of causes, including but not limited to contact with mechanized equipment (mechanical contact), fabrication and handling mishaps (fabrication damage), and pipeline settlement on a rock (rock dents). Mechanical damage in the form of a dent can result from a purely radial deformation, whereas a gouge usually has a component of deformation along the surface of the pipe. For example, a pipe settling on a rock will incur a dent. If the pipe slides on a rock, a dent with a gouge will result. Hence, it is important to identify the causes and types of contributors of damage and deploy effective countermeasures to prevent and mitigate their occurrence.

For onshore transmission pipelines, damage prevention is complex because damage is caused by different types of perpetuators engaged in many different types of activities over many miles of openly accessible rights-of-way.

Although the causes of and consequences from mechanical damage on all underground facilities vary, operators, excavators, and public safety officials recognize the importance of pipeline damage prevention and the need to address the contributing factors concurrently. This section first discusses quality controls and general categories of damage (contact, handling damage, rock dents, etc.). Then, it summarizes commonly used methods, new technologies, and joint government-industry initiatives related to the prevention of mechanical damage.

5.1.1 Mechanical Contact

Controlling contact with mechanized equipment is one of the most effective methods of preventing mechanical damage failure. This is because most pipeline failures and fatalities due to mechanical contact are immediate rather than delayed, and immediate failures can be addressed only by prevention. Failure statistics in the United States indicate that more than 90 percent of reportable damage incidents are immediate failures (Kiefner, 2000).

Parties who operate mechanical equipment in the right-of-way of a pipeline company belong to one of three categories:

- First parties (employees of the pipeline company);
- Second parties (contractors who work for the pipeline company); and
- Third parties (parties who do not work for the pipeline company).

Third parties are responsible for the majority of mechanical damage incidents. Pipeline and Hazardous Materials Safety Administration (PHMSA) data from 2002 to 2008 on significant incidents indicate third parties were responsible for 83 percent of excavation damage incidents that occurred on gas transmission lines and 74 percent of those that impacted liquid pipelines.

Third parties can be further divided into several subcategories, such as other underground facility company employees, public workers, contractors other than those working for underground facility companies, railway company employees, farmers, and other. According to the data collected by the Damage Information Reporting Tool (DIRT), more than 40 percent of underground utility damage (including gas and liquid pipelines, telecommunication and power cables, water lines, and other underground facilities) and near-miss events was reported by developers and by contractors other than those working for an underground facility operator. Another 35 to 40 percent of the damage is caused by the underground facility owner or other utility companies (Hereth, Leewis, and Gailing, 2006A).

Other information concerning causes of damage due to mechanical contact is also available from data on utility damage incidents. Table 5.1 presents the relative frequencies of different outage causes reported in the DIRT data (Common Ground Alliance, 2008, December). The DIRT data shows that the majority of incidents occurred because one-call centers were not notified. In addition, the data suggest that striking a marked utility line (non-adherence to standard excavation practices) is the second leading cause of damage leading to outages. Another important cause is locating/marking errors. Combined, these three categories comprise approximately 99 percent of incidents with known causes.

Table 5.1 Root Causes of Utility Damages (DIRT 2006 data)

Root Cause Category	Distribution in Incident Data
One-call notification practices not sufficient	43.6%
Locating practices not sufficient	17.9%
Excavation practices not sufficient	37.6%
Miscellaneous root causes	0.9%
Events with known data	31.8%
Data not collected, Other	68.2%
TOTAL EVENTS SUBMITTED	100.0%

5.1.2 *Handling Damage*

Mechanical damage can result from mishaps associated with pipe fabrication, stacking, transport, stringing, and lowering. Fabrication and handling damage is usually addressed before a pipeline is put in service, provided the damage is recognized and cut out or otherwise repaired. Nonetheless, damage, such as small dents and gouges, may go undetected.

Some forms of damage incurred during pipe fabrication are *not* mechanical damage but may be confused with mechanical damage when detected by an in-line inspection (ILI) tool or observed in the field. Examples include slugs or roll-ins that work their way free and appear similar to a gouge or metal loss defect.

Backfilling and testing can also be sources of handling damage during construction. Backfilling can cause dents in unpressurized pipe, with the damage tending to be more gradual (e.g., ovalization rather than sharp denting) than when similar defects occur in pressurized pipe. In addition, if re-rounding occurs when the pipe is pressurized, it takes place after the damaging implement is no longer in contact with the pipe. The impact of re-rounding is discussed in Chapter 7.

In testing, rocks, skids (wooden timbers used to hold the pipe during the construction process), rigid ditch breakers, or other objects that result in point loading on the bottom of the pipe can produce dents when the pipe is filled with water for testing. Generally, the higher the diameter-to-wall-thickness ratio of the pipe, the more susceptible it is to this kind of damage.

5.1.3 *Rock Dents*

Rock dents occur when a pipeline settles on an existing rock or ledge or when a rock settles on top of the pipeline. Rock dents differ from damage caused by mechanical contact and fabrication/handling in several respects. Most significantly, the rock typically remains in place after the damage forms, preventing the pipe from re-rounding. In addition, rock dents often do not involve movement or sliding of the rock along the pipe surface. Movement or sliding is typically necessary to gouge (remove) material and significantly damage the microstructure of the steel below the indenter. However, large re-rounding can occur, for example, when rocks are removed at a dent site. It is a known fact that re-rounding often results in microcracks in the dent.

5.1.4 Human Error

Human error can contribute to all types of mechanical damage. Judging from the data shown in Tables 5.1 and 5.2, a large percentage of damage incidents could be attributed to human error. Table 5.2 presents the 2003 to 2005 pipeline incident data reported to PHMSA and analyzed by Hereth, Selig, Leewis, and Zurcher (2006B). Damage on lines that have been correctly marked is included in the "other" category. The data show that more than 60 percent of the damage incidents occurred because operators were not notified.

Table 5.2 Causes of Reportable Pipeline Incidents (PHMSA 2003-2005 data)

Cause Category	Distribution in Incident Data	
	Gas Transmission	Hazardous Liquid Transmission
Operator not notified	62%	66%
Pipeline not marked	17%	8%
Mark incorrect	6%	11%
Other	15%	15%

Inadequate skills and lack of clear and accurate information increase human errors (Hereth et al., 2006A). Human error can be reduced by enhancing communication, improving training, and following established procedures. Campaigns to promote public awareness and safety training are good examples of such efforts.

5.2 Existing Prevention Methods and Technologies

Prevention methods primarily focus on avoiding contact with mechanized or similar equipment. Some methods apply to construction or to farming, to both, or to damage from other causes. The effectiveness of different prevention methods and technologies is discussed based on the expected reduction in the probability of mechanical damage (Chen and Nessim, 1999; Chen and Stephens, 2005; Kiefner, Batte, Broussard, and Gailing, 2007).

5.2.1 Planning and Land Use

Prevention by planning and land use guidelines refers to proactive measures undertaken by pipeline operators to influence the likelihood and extent of future land development and to manage pending development. Measures typically involve communications with land use planners and developers about the implications of possible land use changes and future development plans. Such communications provide information about preventing encroachment and facilitate prevention planning.

PHMSA has partnered with local government planners, home builders, property developers, transmission pipeline operators, and local, state, and federal officials to further enhance pipeline safety in communities. In January, 2008, PHMSA hosted the inaugural meeting of the Pipelines and Informed Planning Alliance (PIPA) to enhance awareness and develop risk-informed guidance for property development in the vicinity of transmission pipelines. The three focus areas of PIPA are:

- **Protecting Communities -** What should pipeline safety stakeholders do, or avoid doing, *adjacent to the pipeline ROW* to reduce the risk to communities?

Figure 5.1 – Pipeline encroachment in residential development.
http://www.apga.org/library/PHMSA%20notices/PIPA_Flier_Final.pdf

- **Protecting Transmission Pipelines -** What should pipeline safety stakeholders do, or avoid doing, *on the ROW* to reduce the risk to transmission pipelines while preserving environmental resources?
- **Protecting Transmission Pipelines -** What should pipeline safety stakeholders do, or avoid doing, *on the ROW* to reduce the risk to transmission pipelines while preserving environmental resources?
- **Risk Communication -** How should the risks to transmission pipelines and communities be communicated to pipeline safety stakeholders?

Information on PIPA can be found at http://primis.phmsa.dot.gov/comm/PIPA.htm.

5.2.2 Damage-Resistant Coatings

Pipelines are generally coated with a multi-layer coating that forms a protective "shield" around the pipeline. The coating prevents moisture from contacting the bare steel and provides a measure of protection against some types of installation and environmental mechanical damage threats. Coatings are typically applied before the pipeline is delivered to the construction site[5]. The ends of the pipe are left bare, typically three to six inches from either end, to facilitate girth welding. The girth weld areas are then coated with suitable materials such as polypropylene, polyethylene, concrete, etc. Various shrink sleeves are also used as girth weld coatings.

Coatings. The resistance to rock penetration of four coatings has been tested in controlled pipe burial tests. (Williamson, Hancock, and Singh, 2000) The pipe coatings evaluated were fusion-bonded epoxy (FBE), two thicknesses of High Performance Composite Coating, and a dual powder system FBE. The coatings incurred progressively greater damage (number of holidays) with an increase in rock size and progressively less coating damage with an increase in coating thickness. The latter was independent of the

[5] This was not always the practice. Many early pipelines were coated at the construction site after individual pipes were welded together.

coating type. A quantitative relationship between coating damage and coating thickness was defined, as shown in Figure 5.2.

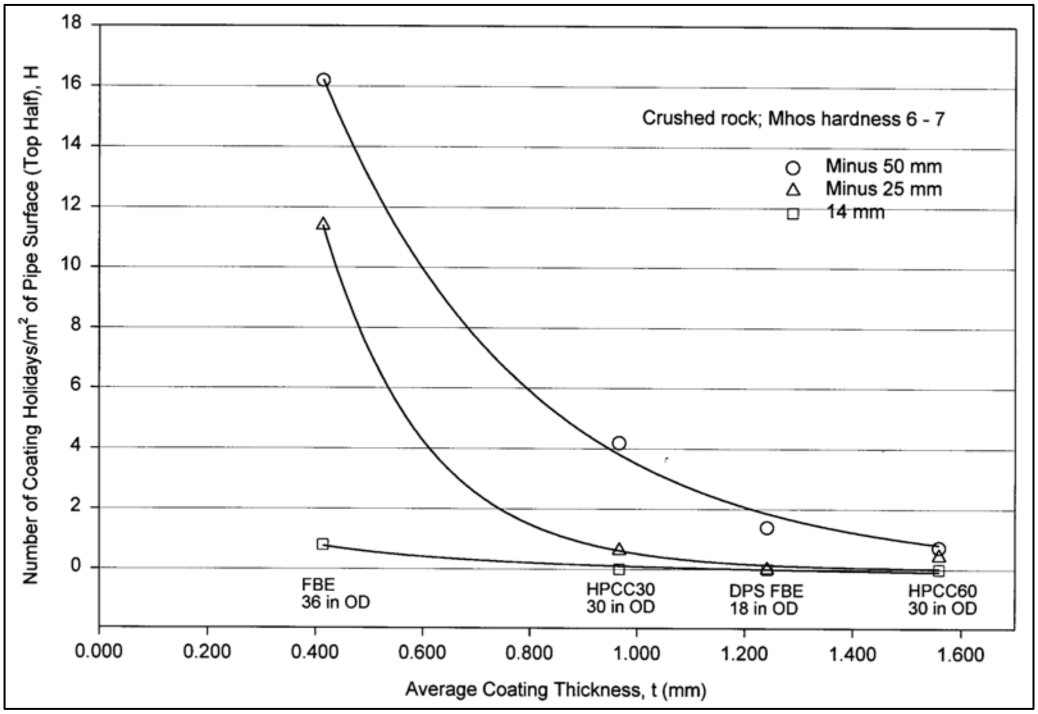


Figure 5.2 – Number of Coating Holidays/m2 of Pipe Surface (top half) Caused During a 12 Day Test of Coating Performance on Buried Pipe

Other tests have evaluated coating resistance to abrasive load. (Christianson, 2006) These tests evaluated two high density polyethylene (HDPE) coatings (HDPE-3 mm and HDPE-10 mm), a polypropylene (PP) coating, a low density polyethylene (LDPE) coating, an FRC coating with PP tape, and two different types of fiber-reinforced concrete (FRC) coatings (FRC-12 mm and FRC-6 mm). Figure 5.3 shows the different types of coatings. The results indicated that

- The low density polyethylene coating exhibited poor ability to withstand abrasive forces.
- The polypropylene coating performed better than the low density polyethylene coating.
- The high density polyethylene coating performed better than the low density polyethylene coating and polypropylene coatings.
- The fiber-reinforced concrete coatings provided good protection against external damage under most conditions. In the tests, the performance of the 6 mm fiber-reinforced concrete coating was comparable to that of the high density polyethylene coating. (Poor coating-to-surface bonding caused the FRC-12 mm coating to peel off as a result of minor mechanical damage).
- Commonly used 3 mm HDPE coating fulfils most requirements in various situations. It has very good mechanical properties, and it is the most economic alternative. For purposes where additional durability is required, a double or triple layer of HDPE provides sufficient protection against most external mechanical damages.

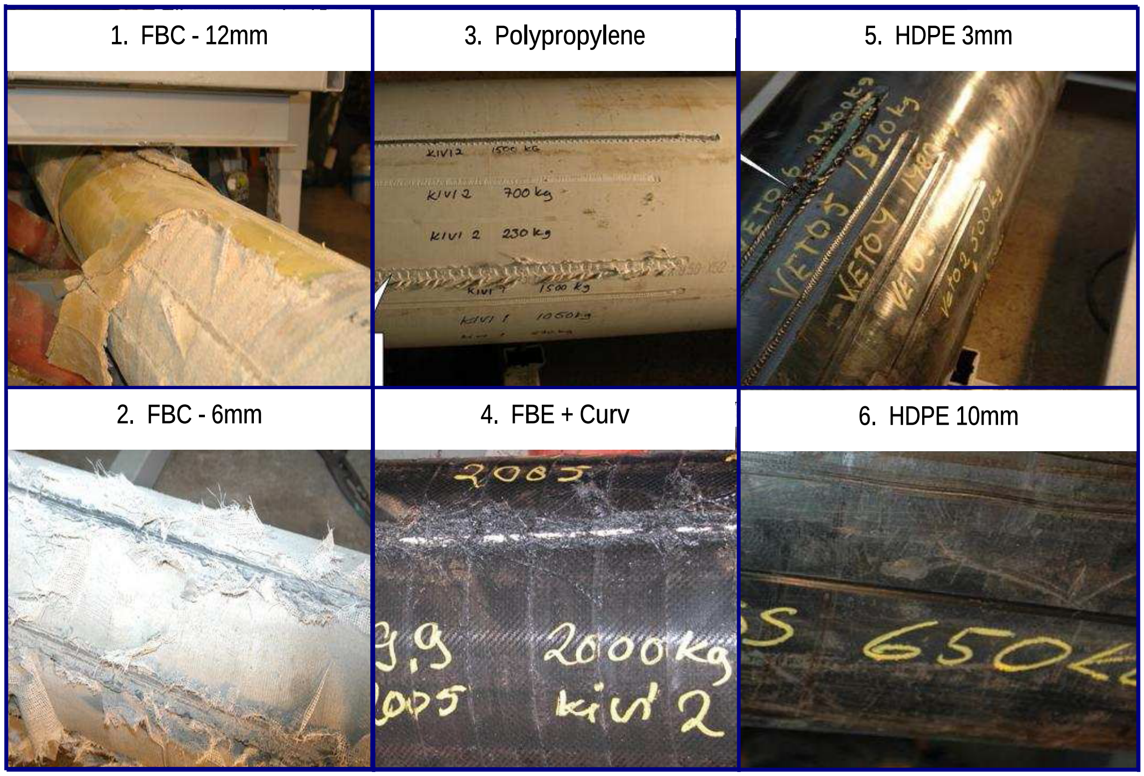


Figure 5.3 – Pipeline Coatings Tested for Severe Construction Conditions (Christianson, 2006)

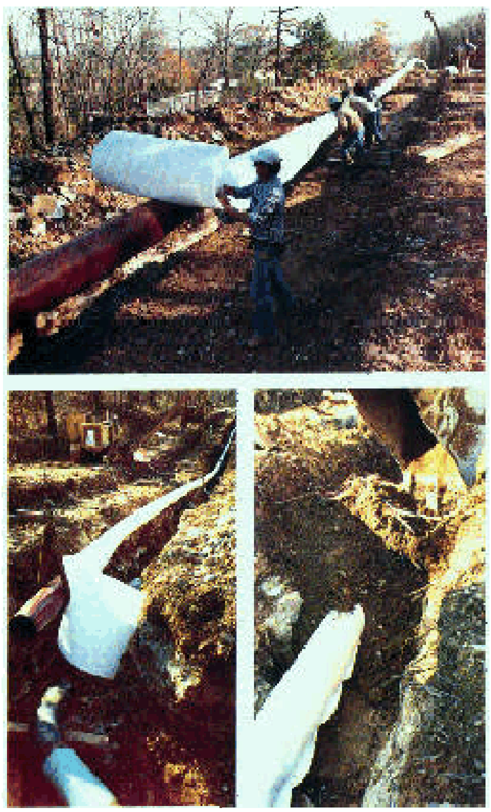
Geosynthetic Fabrics. Geosynthetic fabrics have also been developed to reduce mechanical and other damage due to soil and rock movement. [6] Fabrics with small mesh sizes and high tensile strengths can be used in a single or double layer wrap to reduce axial and/or lateral loads imposed on the pipe by: (1) reducing the direct friction force of the soil on the pipe and/or (2) creating a pre-set slip plane. Geotextiles are commonly available as woven and nonwoven sheets. "Woven" refers to interweaving long, thin fibers into a mesh, whereas "nonwoven" refers to needle-punching the holes to specification in a flexible sheet. General observations related to geosynthetic fabrics and other geotextile wraps are summarized below.

- Two layers of concentric geotextile material reduce the axial loads of the soil on the pipe when compared to a single layer of geotextile or bare pipe.
- If two layers are wrapped on top of each other, the best reduction of axial loads occurs if they are wrapped not in a continuous spiral method, as in a tape wrap, but as individual sections wrapped around the pipe with an overlap between the ends of that section.
- Woven geotextiles are thinner and more flexible (though also not as strong) as the nonwoven.
- The flat planes of nonwoven geotextiles are thought to reduce frictional loads better in theory, though no literature was found comparing the shear stresses between woven and nonwoven geotextiles.

[6] Karimian, Seyed Abdolhamid, "Response of Buried Steel Pipeline Subjected to Longitudinal and Transverse Ground Movement," Thesis Submitted in Partial Fulfillment of the Requirements for the Degree of Doctor of Philosophy, The Faculty of Graduate Studies – Civil Engineering, The University of British Columbia, September 2006.

Dual-layer geosynthetic lining of sloped trench walls has also been applied in an attempt to reduce the likelihood of damage and relieve pipe stresses in active movement regions. Such designs enable the development of a low-friction failure surface away from the pipe-soil interface. The ability to generate such a failure surface reportedly depends on the relative stiffness of in-situ and backfill materials.

Rock Shields. There are a variety of coating types that are meant to protect the pipe from being damaged by rocks in the backfill. Many are wraparound products, similar in many respects to the geotextiles discussed above. Others are flexible mats placed above, below, or around the pipe. Still others are sprayed on in the ditch. Figure 5.4 illustrates such examples.



Composite Foam Cushion Wrap (http://www.farwestcorrosion.com)

Wrapped Rock Shield (http://www.tuff-n-enough.com)

Polyurethane Foam Rock Shield (http://www.pedero.com/)

Figure 5.4 – Examples of Rock Shields

Powercrete®. Powercrete® is an epoxy-based polymer concrete. Its main purpose is to protect the fusion-bonded epoxy coating on steel pipe under severe handling conditions. The highly abrasion-resistant Powercrete® provides a smooth surface that allows the pipeline to be pulled under the crossing in a "slick bore" operation with much less drag resistance than conventional concrete. It has excellent impact resistance and can also be used as a rockshield. Should any damage occur due to severe repeated blows, the area can be repaired easily by using the same material after cleaning, when the surface becomes dry. Figure 5.5 shows an application of Powercrete®.

Figure 5.5 – Powercrete® pipeline coating application (http://www.petropages.com/vendors/v19548.htm)

5.2.3 Lowering and Support

The pipe is lifted, moved, and lowered into the ditch. Long pipe sections are lowered into the trench by special pipe-laying tractors called "side booms." The contractor must exercise care to ensure that the pipe coating is not damaged during the process. In rocky areas, the pipe is placed on one of several different types of supports or "pillows." These supports also prevent the pipeline from laying directly on rock. Typical materials used are sandbags, foam bags, and pre-formed supports. An example is shown below in Figure 5.6.

Figure 5.6 – Pipeline on Foam Supports (http://www.pedero.com)

5.2.4 Backfill

Once the pipe is completely located inside the ditch, the material excavated from the trench is replaced over the pipeline. In rocky areas, a layer of rock-free dirt padding is first placed along the pipe circumference to protect the coating, prior to backfilling. Numerous construction practices are used to minimize the potential for mechanical damage from rocks. Similar techniques are also used after an excavation in areas where third-party damage is considered likely.

Most operators restrict the maximum size of rocks in the backfill. Specialized machines have been developed to shake and filter backfill material down to a specific maximum-size particle. Figure 5.7 shows typical equipment.

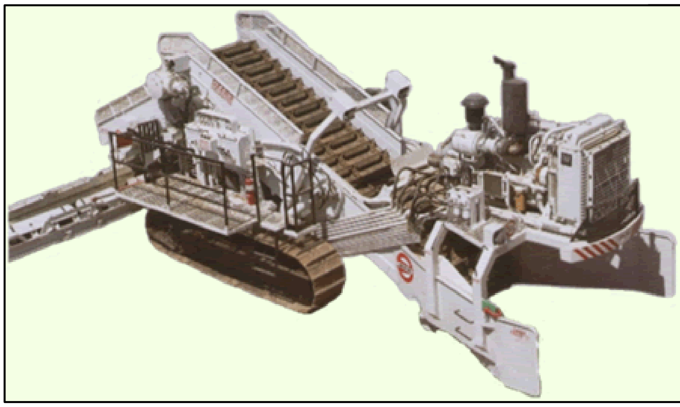


Figure 5.7 – Backfill Screening and Padding Machines (http://www.ozzies.com/ (left); http://www.ezpadding.com/ [right]).

Flowable Fill. Flowable fill is an engineered, controlled, liquid-like fill material – typically a mixture of fly ash, cement, sand, and water – which is self placing, self leveling, self compacting, and nonsettling. Also referred to as controlled low-strength material (CLSM), flowable fill is primarily used as a backfill material in lieu of compacted granular fill. Figure 5.8 illustrates an application of flowable fill.

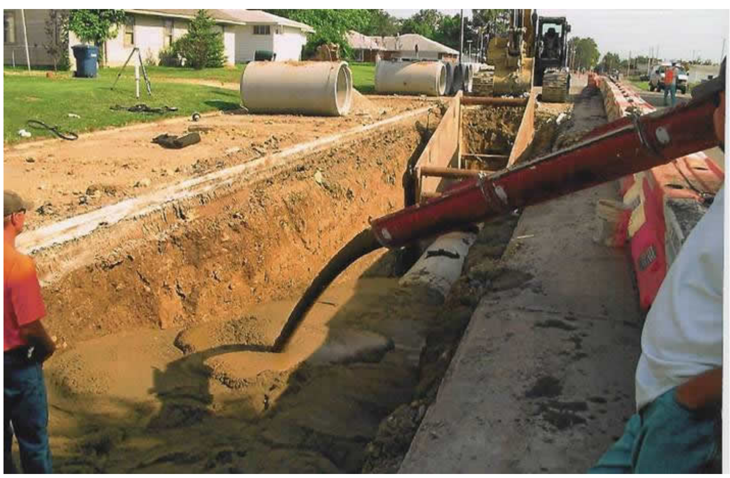


Figure 5.8 – Flowable fill being poured to fill the pipe excavation area. (http://www.irmca.com/Topics/flow.asp)

While flowable fill is not advertised as a measure to prevent future excavation damage to the pipeline, operators who use it indicate that it affords some degree of protection in that the penetration resistance characteristics of the fill material are greater than that of the surrounding soil. A ditch line of flowable fill may also alert equipment operators in advance to the presence of an underground pipeline.

5.2.5 Public Education and Awareness Campaigns

Public education programs heighten awareness of underground pipelines and damage hazards, promote recognition of right-of-way and alignment markers, and emphasize the importance of notification prior to excavation and the use of sound excavation procedures.

Building on the findings and recommendations of the Common Ground Study (1999), a multistakeholder consensus document on damage prevention best practice, the American Petroleum Institute (API) developed a Recommended Practice, API RP 1162. API RP 1162 is used by pipeline operators in establishing and managing public awareness programs (API, 2003). The document provides a comprehensive description of the key elements of a baseline public awareness program and guidance on development of an enhanced program. Included are supplemental elements that may be warranted in areas with "very high population, high turnover, and extensive development and excavation activity."

As outlined in API RP 1162, the primary purpose of a comprehensive public awareness program is to develop and deliver the appropriate message to four target audiences:

- The affected public,
- Emergency officials,
- Local public officials, and
- Excavators (including land developers).

The success of efforts to heighten awareness and understanding for each target group is assumed to be directly dependent on the message content, delivery method, and delivery frequency.

For each group, the recommended message content is a subset of the following elements:

- Function and reliability of the pipeline,
- Awareness of pipeline hazards and prevention measures,
- Information on pipeline location,
- Requirements for excavation notification,
- Awareness of damage prevention measures,
- Recognition of and response to leaks, and
- Access to additional information.

The preferred method of delivery and the frequency of delivery vary with the target audience. The preferred method of delivery to reach the affected public is usually print material targeted to citizens according to their proximity to the pipeline; the required frequency of the mailings ranges from between one and two years. If the communication involves local gas distribution networks, public service announcements or paid advertisements may constitute acceptable alternatives. Some operators add to the requirements of API 1162 by, for example, providing handout information to equipment rental companies.

To reach excavation contractors, the use of print material disseminated on an annual basis is recommended for hazardous liquid and natural gas transmission pipeline operators, while annual group meetings or one-call outreach is recommended for use by operators of local natural gas distribution companies. The preferred method of communication with emergency officials varies depending on the situation and may involve the use of targeted mailings, group meetings, or contact with personnel on an annual basis. Recommended publicity measures targeted to public officials include distribution of print material once every three years. Some operators have created a corporate public awareness staff position to promote public awareness. The individual who serves in such a position is mainly responsible for promoting the continuity and consistency of public awareness initiatives and ensuring adherence to best practices.

Evaluation of the effectiveness of public awareness initiatives is essential to the development and maintenance of a sound public awareness program. However, assessment can be challenging, given that the concept of public awareness is somewhat intangible. Possible measures to evaluate elements and overall program effectiveness include the following:

- Obtaining an objective evaluation (through in-house input or from an independent source) of message clarity,
- Tracking the number of individuals within a target audience that are reached, or alternatively, the percentage of members within a target audience that are reached,
- Using return postcards or similar in mailings,
- Interviewing a sample of persons to whom information was sent, and
- Tracking the increase in the use of one-call systems or the reduction in frequency of third-party damage incidents (assuming land use and activity rates are constant and other unrelated damage management strategies are not concurrently being introduced).

The CGA Best Practices Manual (CGA, 2008, March) and API RP 1166 (API, 2005) have established essential public awareness and contractor training elements for safe excavation procedures.

5.2.6 Marking and Signage

Aboveground signs and other markers are used to alert the public to the presence of a pipeline right-of-way but are not intended to mark the actual pipeline location. ANSI Z535.1 provides guidelines on standard signage colors. 49 CFR Parts 192 and 195, as well as various state regulations identify the minimal data that must be present on the marker. They also provide basic rules for determining marker placement.

Some operators exceed the minimum requirements for right-of-way marking. For example, "line-of-sight" marking, which involves locating signs or other markers within eyeshot, is becoming an increasingly common practice to enable quick identification of the pipeline route. Some pipeline operators also use road markers, tracer tapes, buried electronic markers, and other systems.

The CGA Best Practices Manual (CGA, 2008, March) includes guidelines for markings of pipelines in navigable waters and temporary markers for underwater facilities. In addition to permanent markers placed as close as practical at the entrances and exit point of facilities located underneath bodies of water where facilities are at risk of being damaged., temporary markers such as buoys, poles, or PVC markers are used by underwater facility owners to indicate the presence of an underwater facility in the area.

5.2.7 Right-of-Way Maintenance

Right-of-way maintenance is used to ensure that the pipeline route is clearly delineated and to provide a clear view for aerial monitoring of encroachment. Operator right-of-way maintenance measures vary. To identify the location of buried pipelines within the right-of-way, distinctive marker posts are placed in the ground at intervals above the centerline of the pipeline, or as close as possible. Some operators utilize marker balls to alert excavators about the presence of pipelines. Some operators regularly mow and remove shrubs in the right-of-way, while others allow or encourage the growth of dense vegetation to discourage third-party access. The frequency with which the pipeline right-of-way is cleared ranges from several times per year to once every several years.

Recently, operators have begun to remove an increasing number of trees and structures from the right-of-way, even through residential areas. Trees, extending vegetation (branches), and structures that obstruct the view of the right-of-way are removed to facilitate aerial patrol. In addition, tree roots that extend near the pipeline are removed, since these can also damage the pipeline coating or even the pipe itself. Figure 5.9 shows a cleared right-of-way along a pipeline route.

Figure 5.9 – Illustration of a cleared right-of-way along a pipeline route

5.2.8 Mapping

Pipeline corridor maps or alignment sheets are tools that record the location of pipelines and associated facilities, and as such, are important elements of a damage prevention program. Alignment sheets are traditionally prepared manually or electronically using computer-aided design (CAD) software. The sheets are comprised of plan views (usually in aerial photographs) of the pipeline route and include linear stationing and data strips that display information about pipeline size and materials, elevation, rights-of-way, construction details, crossings, and associated facilities. Alignment sheet information is typically gathered from survey and design drawings over the years.

To assist in the prevention of mechanical damage, pipeline maps must be reliable, accurate, and readily accessible. Map accuracy depends on precision of positioning and access to complete and current facility information. To ensure accessibility, maps must be digitized and compatible with standard geographic information management systems. Accurate, accessible maps enable rapid processing to more effectively allocate prevention resources and ultimately reduce the number of pipeline failures. However, in no instances should even the most accurate maps substitute for field verification of pipeline facilities prior to excavation.

Modern geographic information system (GIS) and global positioning system (GPS) technologies provide interactive and convenient access to pipeline location information. A GIS map incorporates a digital base map that displays surface features, streets, and political boundaries. Layers of information (e.g., buildings or pipelines) can be registered to and superimposed over the base map to present geographically integrated information. In addition, GIS maps can be linked to non-geographical data (e.g., pipe size and cover depth) to provide interactive access. GPS technology utilizes a constellation of satellites that continuously monitor the earth's surface and can be used to identify pipeline location using a handheld device, if the pipeline map information is GPS compatible. Current GPS technology is capable of providing accuracy to the sub-meter level.

However, while GIS and GPS provide convenient access to pipeline maps and databases, their accuracy still relies on the accuracy of the pipeline location data and of the maps used to locate roads, topography, etc. The use of ILI tools equipped with inertial navigation systems and performance of periodic surveys to collect pipeline alignment position can improve pipeline location accuracy. Figure 5.10 shows a pipeline network registered using GIS mapping technology.

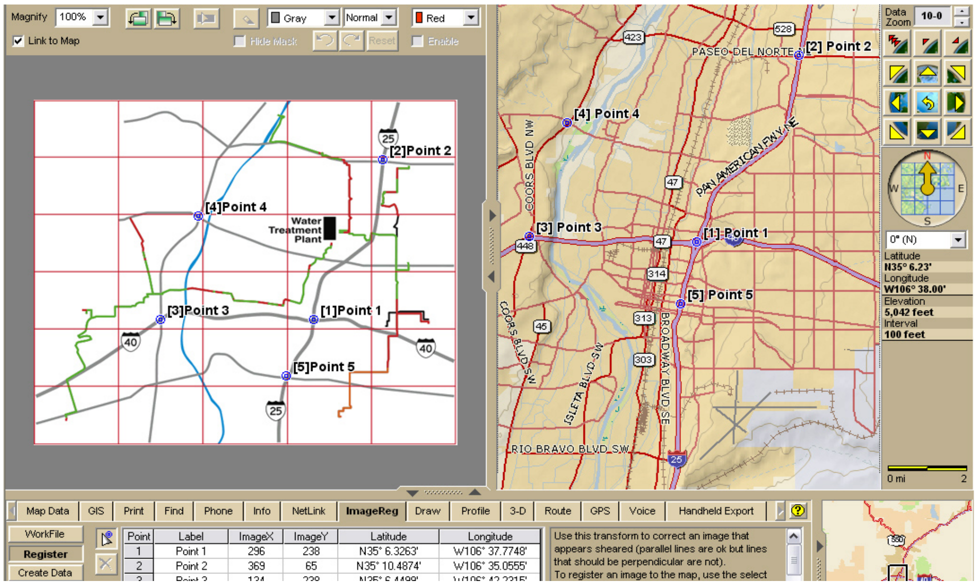


Figure 5.10 – GIS Image of a Pipeline Network

The Common Ground Alliance (CGA) has identified best mapping practices associated with damage prevention (CGA, 2008). The main recommendations include:

- Ensuring that the map data and the historical observations behind it are accurate and updated to reflect existing facilities, new additions, and decommissioned components;
- Providing ready access to latitude and longitude coordinates; and
- Ensuring that the mapping system can produce a locate ticket for the smallest practical geographic area.

A recent survey of 21 pipeline operators (15 in the United States) suggests that the majority of pipeline companies maintain their system maps in GIS or other electronic format (Kiefner et al., 2007). The survey also indicates that improvements in the accuracy of the pipeline maps currently provided to one-call centers can improve one-call efficiency (Hereth et al., 2006A). Many one-call centers still rely on maps which incorporate grids that are too large to identify pipelines that may be affected by pending excavations, resulting in over-notification of possible facility involvement. One-call systems are discussed later in this chapter.

5.2.9 Surveillance

In the context of third-party damage prevention, right-of-way surveillance is the periodic examination of the pipeline right-of-way to detect unauthorized excavation, or recently completed excavation by observing earth disturbance. Typically, pipeline company personnel or contractors perform surveillance, which involves periodic ground-based or aerial patrols. Surveillance effectiveness depends heavily on patrol frequency. If the interval between patrols exceeds the time required for an excavation contractor to mobilize on site and commence digging, surveillance may be ineffective. Analytical models are available to quantitatively estimate the likelihood of excavation detection for a given patrol frequency based a probabilistic characterization of the time from on-site mobilization of excavation equipment to contact with the pipeline (e.g., Chen and Nessim, 1999).

Different types of aerial patrols are conducted. Patrols using fixed wing aircraft and helicopters are most common. Helicopters are preferred by some operators because they can land to immediately address areas of concern. Patrols can also include driving and walking along the right-of-way, especially in areas where aerial access is restricted (e.g., near an airport) or where there is not a clear line of sight from above.

Many operators maintain real-time contact with their surveillance personnel to allow field patrols to rapidly respond to reports of encroachment. Supplementary surveillance methods include inspection of areas surrounding the right-of-way for signs of encroachment, performed by the personnel who mark the lines (for one-call). The frequent presence of company personnel in and around the right-of-way also helps to develop relationships with local contractors and construction companies.

In recent years, there has been an increase in the permanent recordation of surveillance initiatives through media such as videotape or digital photography. The frequency with which a pipeline operator patrols its right-of-way depends on the applicable regulatory requirements and company policy. Patrol frequency generally reflects the type of product being transported and the density of the surrounding population. Pipelines that transport volatile or hazardous products and those that pass through more heavily populated areas tend to be patrolled more frequently.

While more frequent patrols make detection of encroachment more likely, studies have shown that typical patrol frequencies are associated with relatively low probabilities of detecting unauthorized excavations (e.g., Corder, 1995; Chen et. al., 1999). For instance, it was estimated, based on a simple probabilistic model, that a frequency of less than one patrol per month will detect less than five percent of unreported excavations. The effectiveness of periodic patrol does not improve significantly unless the patrol is performed more frequently than weekly (Chen, Davis, and Parker, 2006).

Satellite remote sensing enhances the planning, design, management, operation, and maintenance of pipeline monitoring systems. Multispectral and radar satellite imagery integrated with GIS or CAD can assist in pipeline monitoring and help protect against encroachment. This technology is evolving.

Finally, most operators' surveillance policy includes frequent right-of-way observations by company personnel, whenever feasible. The frequent presence of its personnel in the pipeline right-of-way enables the company to monitor ongoing activities of contractors working in nearby areas and also demonstrates the company's commitment to safety.

5.2.10 One-Call System

The one-call notification process is intended to encourage and facilitate the timely and effective communication of the intent to excavate. The excavating party initiates the process, the one-call center processes the request and notifies underground facilities operators, and the pipeline operators respond to the notification. The set-up of a typical one-call center consists of the following components:

- Operators to receive and record information about pending excavations,
- A database of information about member company facilities,
- Software to search for facilities near the location of pending excavations, and
- A system to alert facility owners via telephone, electronic mail, fax, or dedicated printer.

Specific steps typically followed in the process to prevent mechanical contact with a buried pipeline are detailed below.

1. The excavating party identifies the location and extent of a pending excavation and notifies the one-call center, in some cases, using “electronic white-lining” (discussed in Section 5.3.4) to delineate the excavation area by GPS coordinates;
2. The one-call center searches its database and notifies the pipeline operator(s) whose facilities will be affected by the excavation;
3. If the excavation site is near its pipeline, the operator locates and temporarily marks the pipeline; or
4. Where required by state law, if the operator has no underground facilities in the vicinity of the proposed excavation area, the operator provides a positive notification (i.e., “all clear” or “no conflict”) to the one-call center;
5. The excavating party performs the excavation procedure; and
6. The operator supervises the excavation, if needed.

Additional preventative measures are employed to educate the public about the process and to highlight actions that do not comply. These measures include public education to promote the “call-before-digging” concept, signage to identify pipeline locations, and right-of-way surveillance to prevent unauthorized activities, as discussed earlier.

As of May 1, 2007, 811 was activated as the new national “Call Before You Dig” number. Created through the support of more than 15 industry stakeholder groups, including CGA, who encouraged its development and creation and now promote its use nationwide, 811 eliminates the confusion of multiple “Call Before You Dig” numbers across the country by routing the excavating party’s call to the local one-call center. The call is then handled as described above. Figure 5.11 shows the new 811 emblem.

Figure 5.11 – 811 logo (http://www.call811.com/)

One-call centers are the most commonly used resource for notification. The pipeline facility owners who fund the operation of a one-call center and receive notification services are often referred to as members of the one-call organization. The one-call center enables second and third parties to register their intent to excavate and notifies operators of the planned activity.

When an excavator provides one-call notification of a pending excavation, pipeline maps are used by one-call centers to determine which pipeline companies need to be notified based on pipeline proximity to the excavation site. Once notified, the one-call center determines if the location of the proposed excavation is within proximity of buried facilities based on the records provided by its members. Notifications (or “tickets”) are then sent to all members whose facilities are near the excavation site.

Once the one-call center issues a ticket to a pipeline company, the pipeline operator screens the excavation information using its pipeline database to determine if it is necessary for the operator to mark the pipeline. If the potential exists for pipeline impact, a work order to verify pipeline location is prepared and transmitted electronically to the pipeline company's field locator. The one-call center also notifies the excavating party of the date for the field location.

The overall objective of the one-call system is to notify all potentially affected member companies about a planned excavation so that they can implement measures to prevent damage to their facilities. Factors that influence the effectiveness of a one-call system include, but are not limited to, participation of members, enforcement of the excavation notification requirement, accessibility of the one-call service, positional accuracy of the pipeline grid location system, time required to process notifications, and quality assurance measures to reduce ticket errors. These factors are discussed further below.

5.2.10.1 Participation

Full participation by all utility companies within the same jurisdiction in a single unified one-call organization enables the one-call center to provide the most effective service and therefore maximum value to the public and the center's pipeline members. Limited member participation in a one-call system as well as the presence of multiple one-call centers within the same jurisdiction tend to confuse excavating parties and therefore discourage compliance with notification requirements.

The use of a three-digit nationwide toll-free number to connect one-call centers was mandated by the Pipeline Safety Improvement Act of 2002. The Federal Communications Commission (FCC) approved the 811 number in March 2005, and the service was launched in April 2007. The nationwide toll free number connects individuals desiring to register their intent to excavate with the appropriate local one-call center. It intends to eliminate the confusion of multiple one-call numbers across the United States. Since the announcement of the 811 number, the Common Ground Alliance (CGA) has collaborated with stakeholders and national, regional, and local partners to conduct a public campaign to raise awareness of this service, as discussed later in this section.

5.2.10.2 Enforcement of Notification

Most jurisdictions have established laws to enforce notification compliance. Penalties for not notifying vary from civil penalties enforced through court action, to administrative enforcement with small fines and citations for violation. Experience shows that severe civil penalties are rarely imposed. Many operators consider lack of enforcement to be a key factor in degrading the effectiveness of one-call programs.

Administrative enforcement measures managed through government departments are relatively easy to implement and have proven to be effective. In Massachusetts, 3,000 violation notices were issued from 1986 to the mid-1990s, contributing to a decrease of third-party damage incidents on all types of facilities from 1,138 in 1986 to 421 in 1993. Administrative enforcement was responsible for a 28.5 percent decline in excavation damage to underground lines in Connecticut, as compared to earlier years when enforcement relied on heavy civil penalties.

In an effectiveness analysis using the fault tree method, enforcement of the notification requirement was identified as the most influential factor in reducing the probability of pipeline strikes. It was suggested that the number of pipeline strikes is proportionate to the degree of enforcement (Chen and Chebaro, 2006).

5.2.10.3 Accessibility

Excavation contractors sometimes report that they cannot reach one-call operators. One-call center accessibility is influenced by a center's hours of operation, the number of operators on hand in relation to number of incoming calls, and the availability of alternative methods for notification. The best practices manual published by CGA establishes parameters for the processing of incoming calls. The manual recommends that less than one percent of incoming calls receive a busy signal, and that less than five percent of connected callers be required to wait longer than one minute to be served. In order to provide better service and improve efficiency, some centers offer alternative methods for notification, including fax, voice mail, electronic mail, and Internet access.

5.2.10.4 Positional Accuracy

Following the excavating party's notification of a pending excavation, a one-call center uses a prescribed grid system to identify pipelines believed to be potentially affected. All members whose facilities are located within the same grid as that identified for the excavation are notified. The number of notifications is influenced by the chosen grid size. A one-call center that utilizes a coarse grid system generates unnecessary owner notifications, which imposes a processing burden on both the center itself and the facility owner. It reduces the center's operating efficiency and increases the number of locating and marking responses required of the pipeline owner and associated costs. One pipeline company affiliated with a grid-based one-call center estimates that 40 percent of the excavations reported through the local one-call system are determined not to be in proximity to its pipelines and do not require pipeline locating or marking (HSB, 1997).

Examples of the geographic coverage of commonly used grid systems include quarter sections (a land unit equal 160 acres and measuring 1/2 mile on a side) in rural areas and street blocks or subdivisions within cities. The grid size is primarily limited by the nature of the facility location data stored in the database.

5.2.10.5 Processing Time

The time required to process an excavation notification before tickets are issued to member companies impacts the effectiveness of damage prevention measures. If the one-call service response is delayed, the second or third party may decide to proceed with the excavation before the facility owner has verified the location of and marked its pipeline.

A survey of one-call center processing times showed that 67 percent of tickets were sent to members on the day that the excavation notification call was received; 23 percent were sent on the second day following receipt of the call; nine percent were issued on the third day, and one percent were sent on the fourth day or later (Edge and Woodell, 1997). Comments by pipeline companies generally confirm these statistics.

5.2.10.6 Quality Assurance

Effective quality assurance measures reduce errors in the tickets issued by one-call centers. The measures include conforming to standards such as those recommended by One-Call Systems International. Follow-up communication with contractors to provide contact information for facility owners is a best practice recommended by several studies.

5.2.10.7 Pilot Programs

Conventional one-call systems utilize a grid (quarter sections, legal subdivisions, townships, ranges, etc.) and require notifying all members whose pipelines are located in the same grid section as that of the excavation site. New mapping technologies enable facility locations to be defined in the database using a series of polygons, which include a buffer zone on both sides of the pipeline. In comparison to grid-based systems, polygon-based systems provide more accurate geographic coverage to determine the size of the area affected by an excavation and therefore reduce the processing time for requests and the number of required operator responses.

Several pilot projects that utilize commercially available GIS and GPS technologies to improve the one-call notification process have been performed in recent years, including the Virginia Pilot Project discussed in the next section. Essential components of the technologies that increase accuracy and timeliness of response include:

- GPS-enabled cellular phone use – To identify the excavation site for the one-call center, the excavator uses a GPS-enabled cellular phone (or other GPS device).
- GPS coordinate processing of notifications – One-call centers and pipeline companies process the notification based on GPS coordinates of the excavation site.
- GIS-based one-call database buffer zone definition – Buffer zones surrounding each pipeline are defined in the GIS-based one-call database using a series of polygons, which enables the one-call center to pinpoint the portion of right-of-way for which a notification has been reported.
- GIS-based automated ticket production and processing – One-call centers and pipeline companies use GIS-based automated processes to generate and process one-call tickets.
- GPS use for pipeline location – Locators use GPS devices to assist identifying the exact pipeline alignment.

By reducing the errors in identifying excavation sites and pipeline location, reducing the number of one-call tickets to be investigated, and expediting the notification response process, these new technologies are expected to significantly improve the effectiveness of damage prevention measures.

Another recent development is the use of electronic tickets, transmitted from the one-call center to the pipeline company. An electronic ticket management system can overlay the location of an excavation on a pipeline company's GIS-based system map to determine if the site is within impact distance of the operator's pipeline. Such systems can also schedule field locates and notify the excavation contractor of field location arrangements.

Finally, web-based one-call centers are in place in some locations. Web-based one-call support allows excavators to log in and generate tickets online without being routed through a one-call center operator. Direct access improves accessibility to one-call services and is expected to reduce the number of unauthorized excavations.

5.2.10.8 Virginia Pilot Project

In 2005, the Commonwealth of Virginia, PHMSA, the pipeline industry and other key stakeholders in the U.S. initiated a pilot project to enhance the one-call damage prevention process through the use of global positioning system (GPS) technology. Virginia was chosen as the location for the Project due to its mature, active and inclusive damage prevention program. Additionally, coincident with the implementation of the Pilot Project, Virginia's one-call center developed and implemented enhanced mapping capabilities that complemented the Project technology. Certainly, the potential for application of the technology in all states was a driving consideration throughout the Project.

Phase I of the Virginia Pilot Project, completed in December 2007, focused on improving the locational accuracy of facility locate requests submitted by excavators to the one-call center. This was achieved by the development and use of electronic white-lining. The Project Team combined existing cell phone, Internet, and GPS receiver technologies with the development of specific software applications and enhanced one-call processes.

5.2.10.8.1 Key Results from the Virginia Pilot Project

Several key statistics are reflected in the data generated by the Pilot Project. The results indicate significant improvements in the costs and efficiencies related to implementing one-call damage prevention programs. These in turn should lead to improvements in the benefits of such programs to all stakeholders and to significant improvements in underground facility safety.

- The number of locate notification tickets issued was reduced by 8.04 percent
- The average notification area for locate requests was reduced by 89.42 percent
- 3-hour notices were reduced by 56.78 percent
- Cancelled locate requests were reduced by 36.5 percent
- The need for extended marking schedules was reduced by 66.22 percent
- Incorrect address tickets were reduced by 32.60 percent.
- Tickets with unclear marking instructions were reduced by 91.80 percent
- No ticket with the scope of the excavation larger than allowed by Virginia law was submitted by excavators using the Pilot technology

The above data proves the Pilot Project provided a more efficient locate request process, ensuring that locate requests were processed in a more timely and accurate manner.

The bottom line is that the application of GPS-enhanced electronic white-lining technology to the one-call damage prevention process has been demonstrated through this Pilot Project to benefit the damage prevention process.

5.2.10.8.2 The Path Forward

A bilateral approach will be utilized to promote the benefits of electronic white-lining demonstrated in the Virginia Pilot Program. This will include promoting the benefits to all stakeholders through a nationwide public awareness campaign while concurrently promoting and marketing further implementation of the established process within Virginia.

The results from the Virginia Pilot Project will be submitted to the Common Ground Alliance (CGA) for consideration in the development of damage prevention best practices. The CGA Best Practices are used throughout the industry as guidelines for damage prevention performance.

The technology and processes demonstrated in the Virginia Pilot Project will also be promoted among the various one-call software providers. Currently any Norfield Data Products users will require only slight modification to the one-call software that has already been developed and is in use. IRTH Solutions has begun to develop compatibility with the Virginia Pilot Program process. Between these two one-call software vendors, enhanced electronic white lining as demonstrated in this Pilot Project could be readily developed in a number of states. Obviously, other call centers are encouraged to develop similar software applications to allow the use of the Pilot Project technology.

Phases II and III of the Pilot Project have been discussed by the participating stakeholders as further developments that could increase impact to multiple stakeholders in the one-call process.

Phase II would involve the application of GPS technology to locating instruments and the development of electronic manifests of the locator's activity. It is envisioned that the utility markings would be overlaid onto the ortho-photographic maps to provide a bird's-eye view of the excavation site. This will also improve the detail currently seen in some manifest records. Excavators have indicated they would benefit from having access to the electronic manifests. Utility operators could use the data from Phase II as a verification of their own maps and records.

Phase III would involve the integration of GPS and mapping technology on excavating equipment.

The entire report can be found at
http://primis.phmsa.dot.gov/comm/publications/Virginia_Pilot_Project_Report_Phase_I.pdf

5.2.10.9 Effectiveness

The effectiveness of one-call programs is assessed by tracking whether:

1. The one-call center is notified,
2. The underground facility operators are notified by the one-call center,
3. The pipeline is properly located or marked, and/or
4. The marking is correct.

Historical data on the causes of natural gas and hazardous liquid pipeline damage can be obtained from the incident data collected by PHMSA. Current pipeline incident reporting forms (Incident Report for Gas Distribution System - PHMSA F 7100.1 [03-04]; Incident Report For Gas Transmission and Gathering Systems - PHMSA F 7100.2 [01/02]; Accident Report For Hazardous Liquid Pipelines - PHMSA Form 7000-1[01/01]) collect additional information on the causes of excavation damage incidents.

By reducing the errors in identifying excavation sites and pipeline location, reducing the number of one-call tickets to be investigated, and expediting the notification response process, these new technologies are expected to continue to improve the effectiveness of one-call systems and other damage prevention measures.

5.2.10.10 Locating and Marking

Conventional methods for locating buried pipelines include ground-penetrating radar (GPR), radio frequency detectors, and magnetic or electromagnetic devices. In comparison to remote locating devices, vacuum excavation is considered the most reliable way to simultaneously determine pipeline depth and horizontal location. Figure 5.12 demonstrates the use of the GPR technique. The accuracy of locations performed using remote or indirect techniques depends on the size and burial depth of the pipeline, the proximity of other buried metallic objects, and the skill and experience of the equipment operator. Operator training is therefore a significant factor in the pipeline locating process.

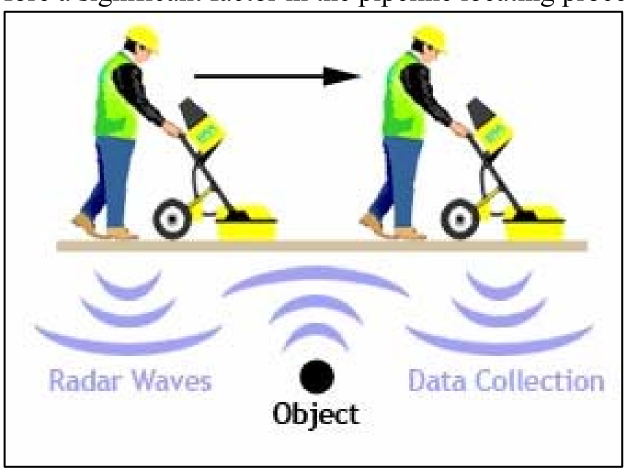


Figure 5.12 – Ground Penetrating Radar (GPR) Technique (Courtesy: http://www.worksmartinc.net)

Field personnel rely on maps and drawings to determine the approximate location of a pipeline. In addition to main lines, abandoned lines and service lines are typically included in pipeline records. In the past, incomplete mapping records and mismarked locations have resulted in damage incidents, some including fatalities.

The marking of a pipeline's location is typically done using spray paint, stakes, and flags. Standards for temporary marking, including color codes for various types of facilities, have been developed by the Utility Location and Coordinating Council (ULCC). The American Public Works Association (APWA) has established color codes to identify different types of underground facilities. The color codes are in general use. APWA encourages public agencies, utilities, contractors, associations, manufacturers, and all others involved in excavation to adopt the ULCC Uniform Color Code using the ANSI Standard Z53.1 Safety Color Code for Marking Physical Hazards. (e.g., oil pipelines are identified with yellow paint or stakes). In addition, the National Utility Locating Contractors Association has proposed standard marking symbols that convey important information about buried facilities (e.g., width, change of direction, and multiple lines).

Pre-marking of the intended excavation area, before pipelines are located and marked, helps to ensure that facilities within the planned excavation area are well identified. Pre-marking is performed by the excavation contractor using (typically white) spray paint to outline the planned excavation. In addition to eliminating errors associated with miscommunication of excavation location, pre-marking avoids unnecessary work from locating and marking outside of the relevant area.

5.2.11 Excavation Procedures

Most operating companies have established and require adherence to formalized excavation procedures that are intended to minimize the potential for contact with the pipe. While the formalized procedures are directly applicable to and strictly enforced for first and second-party excavations (i.e., excavations performed by or for the pipeline operator), they also reflect the operator's approach to third-party excavations.

Key elements of excavation procedures include:

- *Tolerance zones* – to limit the potential for interference between heavy mechanized equipment and the pipe,
- *Selective daylighting* – to confirm pipe location and provide additional visual information to guide the excavation,
- *Equipment safety operating procedures* – to manage the potential for, and severity of, accidental pipeline contact, and
- *Site supervision* – to emphasize the importance of and ensure compliance with prescribed excavation procedures and to minimize the potential for errors in the field.

A communication plan that effectively conveys excavation procedure requirements to the excavation contractor is considered essential.

5.2.11.1 Tolerance Zones

Tolerance zones are areas within which special care must be taken during excavation. Excavation within these areas using heavy mechanized equipment is to be avoided in favor of manual excavation or soft excavation techniques (i.e., use of vacuum excavation techniques or pneumatic hand tools), where practical. The use of other light mechanical tools within tolerance zones may be permitted with pipeline operator approval. The extent of the tolerance zones varies considerably according to the nature of the excavation. Recommended zones can extend as little as six inches (0.15 meters) to as much as five feet

(1.5 meters) from the pipe face in the horizontal plane. Most states, however, have tolerance zones specified in their damage prevention laws that vary from 18 to 30 inches.

5.2.11.2 Selective Daylighting

Daylighting involves manual exposure of selected portions of the pipeline. The need for daylighting is linked to the anticipated separation distance between the edge of the excavation and the pipe face. Daylighting is done to ensure that excavation equipment operators maintain line-of-sight proximity to the buried pipeline while they are excavating. Figure 5.13 shows a daylighted excavated site.

Figure 5.13 – Daylighted Pipeline Site
(Courtesy: http://www.process.sensorsmag.com)

Daylighting is often prescribed for excavations that parallel the pipeline or approach the pipeline if the anticipated separation distance is less than 10 to 15 ft. (3.0 to 4.6 m). Where a pipeline crossing is to occur, daylighting is usually a requirement. The number of daylighted sites depends upon the configuration of the pipeline and the shape and extent of the proposed excavation. Typically, the pipeline is daylighted at planned crossing points and/or at enough locations to clearly convey the position of the alignment. Daylighting at changes in pipeline direction is often required.

5.2.11.3 Equipment Operating Procedures

Many pipeline operators encourage equipment operating practices that are intended to minimize the potential for and/or severity of damage in the event of pipeline contact. These practices include recommendations for the general positioning of equipment relative to the pipeline, the orientation of the excavator bucket swing arc relative to the pipeline alignment during excavation, the direction of bucket travel during disposal of material, and the position of the bucket during its passage over the pipeline.

5.2.11.4 Site Supervision

Site supervision by an operator representative can be essential during an excavation. A decision process is commonly used to screen pending construction activity to determine the need for, and extent of, site supervision. The primary screening criterion is the anticipated proximity of the excavation to the pipeline. API RP 1166, *Excavation Monitoring and Observation*, recommends site monitoring if the excavation is within 25 feet (7.6 meters) and site observation if within five feet (1.5 meters). Excavation monitoring involves a pre-excavation meeting with the contractor and periodic operator presence on site. Excavation observation involves continuous presence on site.

5.2.11.5 Effectiveness

The effectiveness of formalized excavation procedures and protocols in mitigating the potential for mechanical damage is believed to be largely dependent on the following:

- The success of operator efforts to establish an effective working relationship with the contractor to ensure understanding of intended procedures and protocols and to obtain contractor consensus,
- The contractor's pre-existing awareness of and commitment to meeting safety requirements (see public awareness) and the workers' level of skill and experience, and
- The degree to which the contractor actually adheres to procedures.

With respect to the last point, it is emphasized that the excavation procedures advocated by the pipeline operator are not directly enforceable on excavations involving third-party contractors. Because of time and budget constraints, excavation contractors may deviate from established practices. The operator's site representative must often exercise judgment in encouraging or enforcing adherence to excavation procedures, according to situational demands. Some jurisdictions have specific requirements for relevant procedures, such as tolerance zones, but currently this is the exception, rather than the rule.

5.2.11.6 Other Prevention Methods

Concrete or steel plates (or sleeves) and high tensile polymer netting buried above the pipeline practically eliminate the potential for pipe damage. However, field tests conducted by British Gas indicate that physical barriers are still more effective when used in conjunction with explicit warning messages (Corder, 1995).

5.3 Emerging Prevention Technologies

5.3.1 Encroachment Monitoring

As previously indicated, studies have shown that typical patrol frequencies are associated with relatively low probabilities of detecting unauthorized excavations (e.g. Corder, 1995; Chen and Nessim, 1999). To remedy this, technologies are being developed that can detect equipment proximity to the pipeline or sense excavation activity. The technologies reportedly show potential for reducing the required frequency for patrols and increasing the probability of detecting encroachment, while remaining cost competitive. While these technologies do not prevent excavation damage from occurring, they can alert the operator that encroachment has occurred, allowing the operator to investigate whether excavation damage has occurred, ultimately preventing potential delayed mechanical damage failure.

New technologies that have reached the implementation stage or which have had some field trials include the use of satellite monitoring to detect equipment approaching the pipeline right-of-way, and microwave sensing or video monitoring to detect equipment movement in the right-of-way. Future technology includes the use of unmanned airborne vehicles (UAVs), adapted from the defense industry, for pipeline monitoring. A review of research projects and field trials suggests that satellite technology is capable of detecting and discriminating between encroachment and other activities in the right-of-way (Hereth et al., 2006A). The frequency of surveillance provided by the new technologies ranges from days (e.g., satellite monitoring) to continuous, real-time access (e.g., microwave sensing or video monitoring).

5.3.2 Pipe Location Technologies

In order to improve the reliability of current locating tools and overcome the limitations associated with soil variability and signal noise, research is focused on developing multiple sensor systems that synchronize signals from several independent sources to generate more reliable location information.

The magnetic gradiometer is an example of multiple sensor systems. It utilizes military technology designed to detect land and marine mines and features multiple magnetometers that read the intensity and gradient of the magnetic field to identify buried steel pipelines. Preliminary tests show that the magnetic gradiometer can be used to determine buried pipeline location and depth within 2.5-5 cm (one to two inches). Similar to other new locating technologies, the magnetic gradiometer is currently at the development stage. Significant hardware and software developments are needed before a commercial version can be made available.

Buried electronic markers placed above the pipeline can provide a more reliable and effective locating method. These markers consist of an electronic copper coil antenna and can be detected by a special locator. The coil is tuned to respond to a specific radio frequency signal generated by the locator. The antennas are encased in water-resistant polyethylene shells for protection from chemicals and temperature variations typically found in underground environments. The electronic markers are passive and do not require an internal power source. The detectable depth range for electronic markers is between 0.6-2.4 m (two to eight feet), depending on the type of marker used.

APWA provides a standardized guideline for establishing marker frequencies to permit the identification of utility lines by type. A frequency of 83.0 kHz is designated for oil and gas pipelines.

The greatest advantage offered by electronic markers is their accuracy and reliability, according to independent field studies (Muradali, Chen, Lunt, and Nessim, 2003). The primary limiting factor for the technology is that installation for existing pipelines requires excavating on the pipeline alignment.

5.3.3 Contact Monitoring

Several new technologies to monitor pipe contact by excavators have been tested in recent years. These technologies include:

- Acoustic monitoring to detect the noise signature of ground disturbances in the vicinity of the pipeline,
- Fiber-optic cables to detect the light pulse associated with a pipe contact event, and
- Impressed current waveform analysis to detect the AC signal associated with a pipe contact event.

While these new technologies have the potential to enable timely detection of encroachment events, their reliability has yet to be established over the long term (Hereth et al., 2006A). Note that contact monitoring cannot prevent mechanical interference to pipelines.

5.3.4 Obstacle Detection

Several new technologies to monitor pipe contact by excavators have been tested in recent years. These technologies include:

- Acoustic monitoring to detect the noise signature of ground disturbances in the vicinity of the pipeline,
- Fiber-optic cables to detect the light pulse associated with a pipe contact event, and
- Impressed current waveform analysis to detect the AC signal associated with a pipe contact event.

While these new technologies have the potential to enable timely detection of encroachment events, their reliability has yet to be established over the long term (Hereth et al., 2006A). Note that contact monitoring cannot prevent mechanical interference to pipelines.

Intelligent excavation technologies can prevent mechanical interference by enabling excavation equipment to sense proximity to a buried pipeline during an excavation. Induction-based technology involves the use of an electromagnetic transmitter and receiver mounted on excavation equipment. When the receiver detects the pipeline, it alerts the operator, who halts the excavation.

However, the use of intelligent excavation technologies requires that excavation equipment be retrofitted with electronic devices. For the technology to appreciably reduce the incidence of pipeline mechanical damage, a significant percentage of excavation equipment would have to be retrofitted. Because of the cost for retrofitting, it is considered unlikely that these technologies will be broadly applied in the near term.

5.3.5 Electronic White-Lining

"White-lining" is the term used for the excavation contractor's delineation of an excavation area through the painting of white lines on the ground. Electronic white-lining involves the delineation of the excavation area through the use of GPS and electronic mapping technology. (VPP, 2007)

The Virginia State Corporation Commission recently concluded a project to enhance the one-call damage prevention process through the use of GPS technology. The goal of this Virginia Pilot Program, discussed in Section 5.2.10.8, was to leverage advancements in communication technologies during the excavation request process to increase the precision of the area targeted for excavation. The purpose of that communication is to notify the operators to identify and visibly mark the location of their underground facilities before the excavation begins. Utilizing global positioning technology and GIS geo-coding should enable excavators to white-line an excavation site electronically using a PDA or smart phone.

5.4 Government and Industry Initiatives

5.4.1 Common Ground Alliance

Many stakeholders, including the regulatory bodies and pipeline industry members, regard the prevention of mechanical damage as a shared responsibility. CGA is a unique example of a government-industry joint initiative.

The CGA Best Practices were adopted by many organizations and industry trade associations as the basis from which to develop policies and procedures. For example, two recommended practice documents published by API were based on these best practices.

Through the 1990s, the Office of Pipeline Safety (OPS) and other stakeholders jointly performed a series of studies that included the Common Ground Study and studies performed under DAMQAT (Damage Prevention Quality Action Team). Formed in 2000, CGA represents a continuation of the damage prevention efforts embodied by the Common Ground Study. CGA is a member-driven association dedicated to the reduction of damage in underground infrastructure. Today, CGA has more than1,400 members, representing federal and state regulators, utility and pipeline companies, construction contractors, one-call centers, and equipment manufacturers.

CGA's primary functions include:

- Fostering a sense of shared responsibility,

- Supporting research,
- Developing and conducting public awareness and education programs,
- Identifying and disseminating best practices, and,
- Serving as a clearinghouse for damage data collection, analysis, and dissemination.

5.4.2 Best Practices

During the 1999 Common Ground Study, OPS worked with experts representing different industries, communities, and professions to develop a multi-stakeholder consensus document on damage prevention best practices. In total, more than 130 best practices were defined for eight activities. Since then, CGA has continued to periodically update its best practice guide. The latest version (5.0) of the CGA's best practices was published in March 2008. The best practices recommended by CGA were recognized by the National Transportation Safety Board (NTSB) as the guide to prevent underground utility damage.

The best practices developed by CGA (Best Practices Ver.5, 2008) include:

1. Planning & Design Practices
2. One-Call Center Practices
3. Locating & Marking
4. Excavation Practices
5. Mapping Practices
6. Compliance Practices
7. Public Education Practices
8. Reporting & Evaluation Practices
9. Homeland Security and the Best Practices

Building on the findings and recommendations of the Common Ground Study, API RP 1162, used by pipeline operators in developing and managing public awareness programs, provides a comprehensive description of the key elements of a baseline program and guidance on development of an enhanced program (API, 2003). API RP 1162 was subsequently adopted by PHMSA in a final rule, and incorporated into federal regulations 49 CFR Parts 192 and 195. Another API document, API RP 1166, was developed based on a subset of Common Ground best practices for excavation monitoring and observation (API, 2005).

5.4.3 DIRT

To address the lack of data on mechanical damage incidents and excavation activities, CGA launched DIRT in November 2003. DIRT is a secure web application for reporting and collecting information on underground utility damage. It allows the user to submit reports of damage and near-miss events, browse files submitted by the user's organization, and produce reports of its submitted information. Currently, DIRT accepts data from users in the United States and Canada.

For each event logged, the user is asked to describe the extent of damage and identify the root cause. A total of 20 root cause categories were listed in the DIRT field form. Examples of these categories include:

- One-call not notified,
- One-call error,
- Facility not located or marked,
- Marks not maintained,
- Excavation error (equipment hits a marked facility), and
- Other

Since its launch, DIRT has experienced a steady increase in new participants and in the data submitted on an annual basis. In 2005, data on 51,600 damage and near-miss events were submitted to the system. About 91 percent of the data was submitted by owners and operators of underground facilities. Geographically, states in the western United States and the province of Ontario in Canada have led data submission.

User data are analyzed, and summary results are published annually. In addition to delineating incident root causes, DIRT's annual reports include information regarding event location, affected facility, and extent of damage.

The link to the latest DIRT Report issued December 2008 is http://www.commongroundalliance.com/Template.cfm?Section=CGA_News1&CONTENTID=5066&TEMPLATE=/ContentManagement/ContentDisplay.cfm

5.4.4 Grants to States for One-Call and Damage Prevention

Section 2 of the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006 added a new State Damage Prevention Program Grant program to the Federal Pipeline Safety Law as 49 USC §60134. Any state authority that is or will be responsible for preventing damage to underground pipeline facilities designated by the governor is eligible as long as the state participates in the oversight of pipeline transportation pursuant to an annual 49 U.S.C. §60105 certification or 49 U.S.C. §60106 agreement in effect with PHMSA.

The purpose of these grants is to establish comprehensive state programs designed to prevent damage to underground pipelines in states that do not have such programs and to improve damage prevention programs in states that do. The Act sets forth nine elements of an effective state damage prevention program:

- *Element (1):* Participation by operators, excavators, and other stakeholders in the development and implementation of methods for establishing and maintaining effective communications between stakeholders from receipt of an excavation notification until successful completion of the excavation, as appropriate.
- *Element (2):* A process for fostering and ensuring the support and partnership of stakeholders, including excavators, operators, locators, designers, and local government in all phases of the program.
- *Element (3):* A process for reviewing the adequacy of a pipeline operator's internal performance measures regarding persons performing locating services and quality assurance programs.
- *Element (4):* Participation by operators, excavators, and other stakeholders in the development and implementation of effective employee training programs to ensure that operators, the one-call center, the enforcing agency, and the excavators have partnered to design and implement training for the employees of operators, excavators, and locators.
- *Element (5):* A process for fostering and ensuring active participation by all stakeholders in public education for damage prevention activities.
- *Element (6):* A process for resolving disputes that defines the state authority's role as a partner and facilitator to resolve issues.
- *Element (7):* Enforcement of state damage prevention laws and regulations for all aspects of the damage prevention process, including public education, and the use of civil penalties for violations assessable by the appropriate state authority.
- *Element (8):* A process for fostering and promoting the use, by all appropriate stakeholders, of improving technologies that may enhance communications, underground pipeline locating capability, and gathering and analyzing information about the accuracy and effectiveness of locating programs.

- *Element (9):* A process for review and analysis of the effectiveness of each program element, including a means for implementing improvements identified by such program reviews.

Grants awarded under the State Damage Prevention Program are intended for states to establish or improve the overall quality and effectiveness of their programs that are designed to prevent damage to underground pipeline facilities.

A full description of this program is available at http://primis.phmsa.dot.gov/comm/DamagePreventionGrantsToStates.htm

5.4.5 Advisory Bulletins

PHMSA has consistently taken a non-regulatory approach to pipeline damage prevention. However, PHMSA has used Advisory Bulletins to emphasize important actions pipeline operators can take to protect their pipelines. PHMSA uses Advisory Bulletins to inform affected pipeline operators and Federal and state pipeline safety personnel of matters that have the potential of becoming safety or environmental risks.

In May 2002, PHMSA urged pipeline operators to follow the CGA Best Practices for damage prevention. In January 2006, PHMSA described preventable accidents caused by construction-related damage and called on operators to ensure they use qualified personnel to perform critical damage prevention tasks. In November 2006, PHMSA emphasized the importance of following damage prevention best practices, especially for marking the location of underground pipelines prior to excavation.

5.5 Summary

Pipeline mechanical damage is one of the single greatest threats faced by all pipeline companies transporting oil, gas, and hazardous materials. This section summarizes commonly used methods, new technologies, and joint government-industry initiatives for the prevention of mechanical interference.

Prevention is considered the most effective means of reducing damage to human life, property, and the environment from pipeline incidents. Current best practices discussed that support the prevention approach include use of the one-call system, implementation of public awareness initiatives, and enforcement of standard excavation procedures. Continuing research on new technologies, including those to enhance one-call center operation and operator response capability, and right-of-way marking and encroachment detection, is recommended.

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6 Detection, Identification, and Characterization

6.1 Overview

As discussed previously in this report, the instances of delayed failure caused by mechanical damage as compared with immediate failure due to excavation damage are very low. In many cases, finding latent mechanical damage is an opportunistic event. Operators typically do not, and should not, conduct inspections primarily or specifically to find mechanical damage unless it is being done for cause, such as evidence of a recent but unreported excavation.

Because mechanical damage occurs despite the prevention practices discussed in Section 5, this section examines the methods by which latent damage can be detected, identified, and characterized.

6.1.1 Definitions

Key terms used in this section include the following:

- Detection – finding and reporting that an anomaly exists on a pipeline. Detection during an in-line inspection (ILI) means to sense or obtain a measurable signal that is interpreted as an anomaly (defect, imperfection or feature).
- Identification – determining the type of anomaly after it has been detected (i.e., identifying an anomaly as a dent rather than metal loss). Detection and Identification are sometimes grouped together.
- Characterization – estimating the size or characteristics of the anomaly. Characterization includes but is not necessarily limited to determining the size of an anomaly, its orientation, its proximity to other anomalies or features, and the presence or absence of secondary features, such as cracks in a gouge.

Mechanical damage can be detected in a variety of ways, such as by ILI, aboveground surveys, and direct examination. However, identifying the damage as mechanical and not, for example, metal loss corrosion, is not always straightforward. In addition, no one inspection or survey tool is able to detect, identify, and characterize all anomalies under all conditions with 100 percent certainty.

6.1.2 General Features of Mechanical Damage

There are many features or characteristics of mechanical damage that affect its severity, as discussed more fully in Chapters 4 and 7. Common characteristics include those identified below.

- Changes in pipe shape, as defined by:
  - Dent depth, sharpness, and axial and circumferential extent.
  - Axial position and orientation (angle to the pipe axis) and circumferential position.
  - Proximity to a weld, bend, or other stress riser.
- Reductions in wall thickness, such as the presence, extent, and severity of coincidental metal loss (e.g., due to corrosion or gouging) and local wall thinning.
- Changes of pipe material properties due, for example, to the presence, extent, and severity of severely cold-worked material.
- Change to the localized distribution of stresses, strains, and/or loading, such as residual stresses and plastic strains introduced by the damaging process.
- Characteristics of the pipe itself, including the toughness as measured by Charpy absorbed energy, the transition temperature relative to the operating temperature, and the yield/tensile ratio.
- Other anomalies, such as re-rounding or stress-corrosion cracking.

Detecting, identifying, and characterizing these factors is the subject of this chapter.

6.1.3 Chapter Organization and Scope

This chapter discusses commonly used methods of detecting, identifying, locating, and characterizing mechanical damage, starting with ILI, followed by aboveground surveys, and direct examination. Less commonly used (and often prototype or research-associated) methods are discussed at the end of the chapter.

Brief summaries of technological tool evaluations from tool vendors and other industry experts are presented, but a comprehensive evaluation of actual tool performance is beyond the scope of this report. Ongoing studies, supported by the Pipeline Hazardous Material Safety Administration (PHMSA), Pipeline Research Council International (PRCI), and others, are being conducted to evaluate tool performance in relationship to mechanical damage.

6.2 In-Line Inspection

6.2.1 Introduction

The oil and gas industries have used scrubbing and scraping devices called "pigs" to clean the inside of piping systems for decades as a part of maintenance programs. Such "pigging" operations are usually conducted to minimize internal corrosion and thereby help to maintain pipeline integrity.

In addition to cleaning pipelines, tools have been designed to inspect pipelines for evidence of internal or external corrosion, dents, gouges, etc. Sophisticated and sensitive ILI tools, referred to as intelligent or smart pigs, travel through the pipe and measure and record irregularities that may represent changes in wall thickness associated with corrosion, cracks, deformations (dents, gouges, etc.), or other defects. ILI tools are self-contained systems that can be composed of single or multiple segments containing power, drive, sensing, and data storage systems. Many are designed to sense wall thickness and other geometric changes, and are propelled by the pressure of the product being transported through the pipeline.

Dents or other bore restrictions and deformations (e.g., ovalities, cross-sectional flattening, and wrinkles/buckles) are most commonly detected, identified, and characterized using dimensional or geometry ILI tools (calipers). Wall loss is commonly detected, identified, and characterized using magnetic flux leakage (MFL) and ultrasonic technologies. Coating damage or disbondment, which may indicate mechanical damage, is sometimes detected with ultrasonic ILI technologies, such as tools using electromagnetic acoustic transducer (EMATs). Similarly, cracks can sometimes be found using ultrasonic and/or MFL ILI tools.

No existing ILI tool or aboveground survey method detects, identifies, and characterizes the full range of features associated with mechanical damage. Nonetheless, it is often possible to infer the type of mechanical damage by other considerations, such as:

- Top-of-pipe deformation (8 o'clock to 4 o'clock), possibly due to third-party damage.
- Bottom-of-pipe deformation, possibly due to rocks.
- New metal loss in areas where third-party activity is suspected, possibly indicative of mechanical damage.

The presence of mechanical damage itself often compromises the reliability and accuracy of ILI tool performance, and therefore, the validity of the data gathered during an ILI. Specific challenges to the use of current ILI tools include:

- Signal loss or degradation caused by sensor lift off as the inspection device transverses a dent region or encounters other geometric anomalies that may or may not be associated with mechanical damage.
- In weld regions, the presence of weld-backing bars and fabrication anomalies, in addition to material changes in these regions that complicate signal interpretation.
- Severe damage could compromise ILI tool sensor performance, resulting in the inability to inspect the pipeline downstream of the point of damage.

6.2.2 ILI Tool Selection for Mechanical Damage

To select an inspection tool, pipeline operators in their preassessment phase must assess risks or threats to the pipeline's integrity (type of mechanical damage expected, such as dents, gouges, or scrapes) in conjunction with the pipeline's characteristics (such as diameter, wall thickness, weld type, media, pressure, and flow rate). Critical elements of ILI tool selection should be discussed, as required in API 1163, with the potential service providers before putting a pig in the line and include:

- Sensor technology and mechanical design, which is dictated by the type of anomaly to be detected and the platform selected.
- Platform design, adapted for pipelines that can pass a traditional platform inspection tool (piggable), or for dual-diameter pipelines that are unable to pass a traditional platform inspection tool (non-piggable – e.g., multiple and significant bore size changes or low-pressure systems).
- Post-run data analysis, to interpret signal data and identify critical integrity features.
- Accuracy of inspection results, which influences subsequent integrity decisions and requires that the observations collected in the excavation be communicated with the service provider to ensure continuous improvement.

To assist the operator in selection of appropriate tools for an inspection, NACE RP 0102 presents a matrix of pipeline defects and the ILI technologies available to detect them. (NACE) Table 6.1, taken in part from NACE RP 0102 and modified by the authors, summarizes ILI capabilities of commonly available technologies as they relate to mechanical damage.

Some available ILI tools employ multiple types of sensors to detect and discriminate among mechanical damage features. Multiple-sensor tools, either commercially available or in development, employ one or more of the following types of sensors: geometry or dimensional (caliper), electromagnetic (MFL, dual field MFL, eddy current, nonlinear harmonics), and/or ultrasonic (UT; EMAT).

Vendors emphasize that for each inspection tool, trained analysts must interpret the signal data to detect, identify and characterize defects. The basic technologies that underlie current and developing tools designed for mechanical damage detection, identification, and characterization are summarized in the following sections. The deployment of tools and certain claims for particular applications are also reviewed.

Table 6.1 ILI Capabilities related to Mechanical Damage
(Adapted, in Part, from NACE RP 0102-2002, with Modifications by Authors)

Pipeline Defects	Metal Loss Tools		Ultrasonic Compression Wave	Crack Detection Tools		Geometry Tools		Applicability to Mechanical Damage
	Standard Resolution MFL	High Resolution MFL		Ultrasonic Shear Wave)	Transverse MFL	Caliper	Mapping	
Metal Loss (Corrosion)	Detection, sizing	Detection, sizing	Detection, sizing	Detection, sizing	Detection, sizing	No detection	No detection	Stress amplification (see gouges)
Axial Cracks and Crack-like Defects	No detection	No detection	No detection	Detection, sizing	Detection, sizing	No detection	No detection	Significant secondary feature
Circumferential Cracking	No detection	Limited detection, sizing	No detection	Detection, sizing (some tools)	No detection	No detection	No detection	Significant secondary feature
Dents and Wrinkles	Some detection	Some detection	Detection, some sizing	Some detection	Detection	Detection, sizing	Detection	Primary feature, stress amplification, some metallurgical changes
Buckles	When Detected, Circumferential Position is Provided					Detection, some sizing	Detection	Primary feature
Gouges	Detection, but typically no Discrimination as Gouges						No Detection	Primary feature, stress amplification, metallurgical changes
Ovalities	No detection	No detection	No detection	No detection	No detection	Detection, sizing	Detection	Secondary feature
Notes: Detection limits and sizing accuracies vary with tool and defect geometry								

6.2.3 Geometry Tools

The most basic ILI tools for mechanical damage are deformation and/or caliper tools. These tools measure dent depth on the inner surface of the pipe. Caliper tools are not capable of determining metal loss (external), moved metal, cold-working, or cracking associated with mechanical damage. That is, damage, such as a gouge or scratch that does not create a dent detectable on the inner surface cannot be detected by caliper tools. Because the detection and reporting threshold for some tools can be as large as two percent of the outside diameter, these tools can miss some damage that has rerounded to less than the reported threshold.

6.2.3.1 Theory and Application

Geometry tools measure the physical shape or geometry of the inside surface of a pipeline to detect, identify, and characterize dents, buckles, ovalities, and wrinkles. Geometry tools also generally detect and locate mainline valves, some welds, fittings, and other appurtenances.

Most geometry tools typically utilize a set of mechanical fingers, rollers, or sensors that ride against the internal surface of the pipe. Other tools use electromagnetic sensors, ultrasonic compression beam sensors, or accelerometers. Contact with the pipe wall throughout the inspection is critical for most mechanical geometry tools to reliably detect dents and other distortions. Photographs of typical mechanical caliper tools are provided in Figure 6.1.

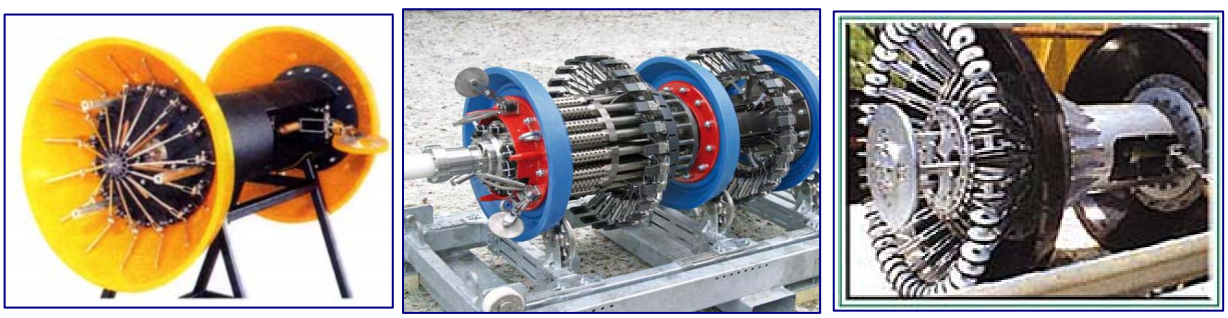

Figure 6.1 – Mechanical Caliper Tools (photos courtesy of Enduro, Rosen, and RAS GmbH)

Some geometry tools also include inertial sensors or gyroscope systems to register the dynamic behavior of the pig as it moves through the pipeline. These capabilities, which are referred to as “mapping” in this report, are designed to provide information about pipeline profile, bend radii, and other large-scale geometric changes.

<u>Resolution</u>

Caliper tools are generally placed into one of two categories based on the number and spacing of sensors:

- Low-resolution caliper tools typically have few sensors, and each sensor covers (contacts) a large portion of the pipe circumference. Because the contact area is large, the reported clock position and circumferential width is approximate. Some inspection companies report only axial position with no circumferential location. Low-resolution caliper tools are often designed to be rugged and to pass through large bore restrictions. Since the data storage and analysis requirements are small, they permit rapid analysis of data and reduced cost of inspection. These tools are routinely used by pipeline companies on new construction as well as prior to performing more detailed inspections to verify that there are no bore restrictions that would damage the more expensive ILI tools.
- High-resolution tools incorporate more sensors, some of which are spaced less than one inch apart around the pipe’s circumference. The increased number of sensors typically results in a

much higher spatial resolution than that achieved by low-resolution tools. Nearly all ultrasonic geometry tools fall into the high-resolution category.

Mechanical Geometry Tools

Mechanical fingers or sensors are typically held against the pipe wall by a spring-mounted armature. Alternatively, the sensors may be mounted in or behind a cup on the pig, or the mounts used for other sensors (e.g., MFL sensors) can be instrumented to allow geometry measurements.

Armature assemblies affect sensor movement and tool accuracy. Important design factors include mass and stiffness. Some tools use a mounting system that allows measurements of sensor rotation in one or more directions (e.g., side-to-side) to increase accuracy. The spring mounting systems for MFL sensors are sometimes instrumented to measure deformations, as discussed later in this chapter.

The ability of geometry tools to provide full circumferential coverage is a significant design consideration. Some tools include a leading and trailing set of sensors that are circumferentially offset so that the trailing set of sensors can catch deformations that may have passed undetected between the leading set of sensors.

One vendor is implementing a "touchless measurement technology." The technology includes measurement of the distance between the deformation sensor and the pipe wall, which in combination with the deflected angle of the caliper arm, compensates for the dynamic movement of the arm, which is reported to provide improved accuracy. (Paeper, Brown, and Beuker, 2006)

Ultrasonic Geometry Tools

Ultrasonic geometry tools use compression beam sensors directed toward the pipe wall to map the inside surface. Most or all ultrasonic geometry tools do not require the sensor (transducer) to be in contact with the pipe wall. Instead, the sensors are mounted on the body of the tool, away from the pipe wall. As a result, this type of tool is less sensitive to problems associated with sensor movement or bounce.

6.2.3.2 Detection, Identification, and Characterization Capabilities

The technology used in geometry tools is fairly well advanced, which can be attributed to the long history and widespread use of the tools for deformation detection. Single and multi-channel tools are readily available from most vendors. As noted earlier, they can only detect mechanical damage features that affect pipe shape and not (external) metal loss, metallurgical damage, or cracking.

Geometry tools are considered reliable at detecting and identifying dents, provided the dent depth exceeds the reporting threshold. Typical reporting thresholds are given in percent diameter (e.g., one to two percent) or in absolute terms (e.g., 0.1 inch, 2.5 mm).

A recent study on mechanical damage detection found that two-thirds of the dents observed during excavation activities on one pipeline were not reported by the geometry tool. (Olsen, 2004) The study noted that in most cases the dent could be observed in the raw data, but the depth was below the vendor's reporting threshold.

Characterization accuracies for dent depths are also given in percent diameter (e.g., +/- one to two percent) or in absolute terms (e.g., +/- 0.03 to 0.05 inches, 0.8 to 1.28 mm). Accuracy is a function of the circumferential resolution and coverage of the sensing area. (Paeper et al., 2006), and higher resolution tools reportedly provide higher accuracy. (Bubenik and Nestleroth, 2000) It is difficult to quantify the actual accuracy, though, because the act of exposing a pipe can allow re-rounding.

Detection and characterization performance is degraded when there is debris in the pipe. Debris can affect whether mechanical sensors maintain contact with the inside pipe wall and can interrupt ultrasonic waves used in other tool applications. Debris typically introduces uncertainty and background noise. Inspection tool speed can also affect the measurements, especially with mechanical systems. As the velocity of the inspection tool increases, the sensor-mounting arm becomes increasingly prone to lose contact with the internal pipe wall or bounce, resulting in errors in measurement.

6.2.3.3 Development Trends

Research in the use of geometry tools to detect and measure pipeline deformations is concentrated on higher resolution tools and on updating or enhancing current technologies. An additional focus involves development of sensor-to-platform attachments that permit independent movement of components and improve measurement ability. (Eiber, 2003)

6.2.4 MFL Tools

MFL tools are the most prevalent inspection method for pipelines. The tools have traditionally been used to detect, locate, and characterize metal loss anomalies. Their capabilities with respect to mechanical damage are evolving.

6.2.4.1 Tool Theory and Application

MFL tool application involves the induction of a magnetic field into the pipe wall between the poles of a magnet system. Pipe walls that contain no defects act as the preferred path for the magnetic flux, and most of the flux remains in the pipe. The presence of metal loss or anomalies causes a disturbance in the magnetic flux, which is detected by a sensor that measures the flux that leaks out just inside the pipe wall.

The relationship between defect geometry and the MFL signal is complex. For metal loss, the geometry is inferred using algorithms rather than directly measured. A schematic of an MFL tool is provided in Figure 6.2. (Clapman, Babbar, Rahim, and Atherton, 2002)

An MFL signal is predominantly a function of the metal loss geometry, but it is also affected by the magnetic properties of the steel, as well as variations in microstructure, stress, and strain. In addition, the signal depends on parameters such as the level of background magnetization, speed of the inspection tool, orientation of the sensor relative to the pipe wall, and liftoff of the sensor.

MFL tools are generally classified as low (or standard) resolution, high resolution, and (sometimes) ultrahigh resolution devices. These classifications are general and not necessarily consistent within the industry (i.e., the definition of high and ultrahigh resolution may vary among companies). Another distinction among MFL tool types is the direction of magnetization (axial versus circumferential) and the magnetic field strength.

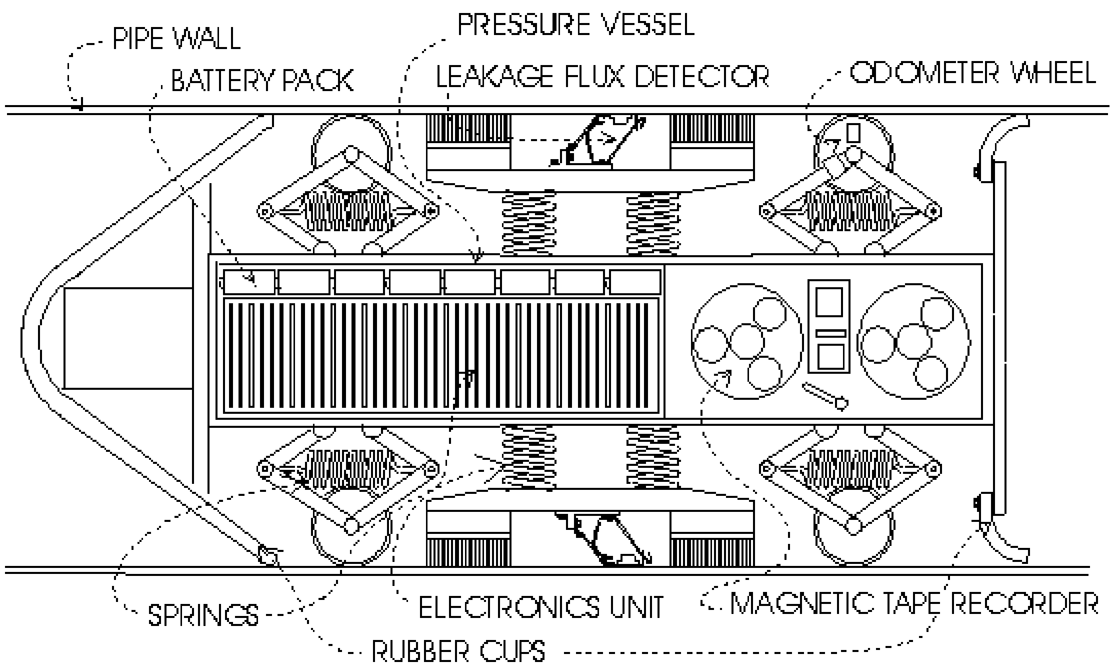

Figure 6.2 – Schematic of MFL Principle (Clapman et al., 2002)

Resolution and Direction of Measurement

MFL fields have both magnitude (strength) and direction. Sensors record the field in a particular direction over an aperture (area). Most commonly, the field is measured in the radial or axial direction (see Figure 6.3). Some vendors currently offer or are pursuing the development of tri-axial sensors to measure all three components of the flux leakage signal in an attempt to better characterize detected anomalies. (Eiber, 2003; Porter, 2006; Cholowsky and Westwood, 2004; GE Oil and Gas, 2006)

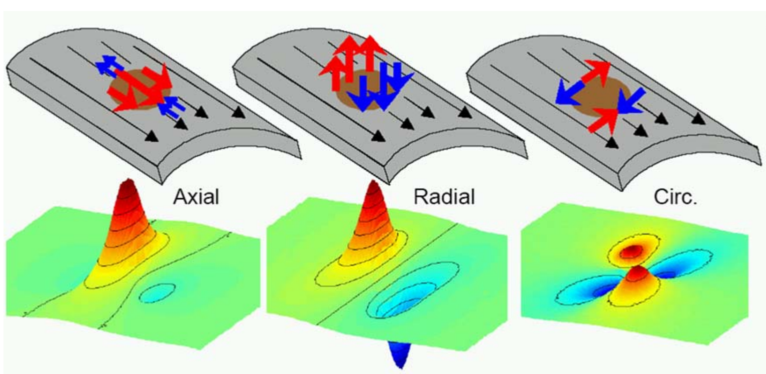

Figure 6.3 – Example of Axial, Radial and Circumferential MFL Signal at Metal Loss Region.

Standard resolution MFL tools are often defined as using sensors that are one or more inches in width (circumferentially). Such large sensors are nearly always "coils" that respond to (measure) changing magnetic fields. The tools record the change in magnetic field strength over the area enclosed by the coil itself. The recorded measurements can be integrated to determine the actual field. Coil sensors were used on all early tools because they do not require a power source to operate.

High resolution tools employ smaller and more densely spaced sensors. Smaller sensors allow a more localized measurement of the leakage field. Many high resolution tools use “Hall effect” sensors, which measure the magnetic field directly rather than the change in field. Unlike coil sensors, the sensor output does not need to be integrated to determine signal strength. The aperture of a Hall effect sensor is very small and the recorded field is usually considered a point measurement.

The basic capabilities of axial, circumferential, and tri-axial MFL sensors with regard to detection and characterization of mechanical damage features are summarized in Table 6.2.

Table 6.2 Comparison of Capabilities for MFL Sensor Directions (Axially Oriented Magnetic Fields)

Capability	Axial (7, 21, 34, & 35)	Circumferential (36)	Tri-axial (12, 13, 23, & 37)
Deformation	May detect dents Possibly detect gouges in dents (characterization unlikely)	May detect dents Possibly detect gouges in dents (characterization unlikely). May detect dents and dents with gouges; If damage includes cracks, may detect larger cracks	May detect dents, gouges, and cracks
Metal Loss	Detect and measures most types of metal loss; more sensitive to circumferential metal loss than axial metal loss	May detect axially oriented metal loss; much less sensitive when the magnetic field is axial than when it is circumferential	May detect axial and circumferentially oriented metal loss
Cracks	May detect circumferential cracks, including those in girth welds	If damage includes cracks, may detect larger cracks. May be able to detect axial pipe wall defects	May detect cracks in dents

Direction of Applied Field

In addition to direction of measurement, discussed above, the applied magnetic field has a direction. Most MFL tools apply a magnetic field along the length of the pipeline. This makes the tool most sensitive to anomalies that cross the field; circumferentially wide anomalies are more readily detected than circumferentially narrow anomalies.

Axially oriented magnetic fields have been used in MFL tools since the 1960s, while circumferential fields are relatively new. Circumferential MFL tools were developed to detect and size defects that are oriented primarily in the axial direction; these defects are generally less reliably detected by axial MFL tools. Recent studies suggest that axial MFL alone is not sufficient to fully characterize the signal derived from a mechanical damage defect. (Clapman et al., 2002)

Magnetization Level

Early MFL tools incorporated permanent magnets or electromagnets to produce a desired magnetization level. The levels reached were low compared to those achievable through application of current tools because available magnet systems were relatively weak. The fields were near the “knee” of the magnetization curve, well below saturation levels.

As inspection technologies evolved, more powerful magnet systems were developed. These systems are capable of producing magnetization levels near saturation levels. High fields provide several important advantages when used for metal loss. At saturation, the leakage field is largely due to metal loss alone, while near the knee, the shape of the magnetization curve is affected by microstructural variations, stress, strain, and other factors. Inspections conducted at high magnetization levels simplify the interpretation of signals that identify metal loss.

A number of attempts have been made to develop tools that can reliably detect and characterize both metal loss and conditions associated with mechanical damage. Some of these tools use dual magnetizing systems – one near saturation and one near the knee of the magnetization curve. By scaling and subtracting the metal loss signal (at saturation) from the combined metal loss/mechanical damage signal (near the knee), information on differences in magnetic properties can be obtained. (Nestleroth, 2007) One or more vendors are presently evaluating the use of dual magnetization levels to discriminate gouges and the stress and strain fields associated with mechanical damage.

6.2.4.2 Detection, Identification, and Characterization Capabilities

Of the MFL tools, axial MFL is still the most prevalent and is readily available from vendors. The resolution of MFL tools has increased, leading to increased sensitivity and improved characterization capabilities.

Dents and Deformations

While the primary purpose of most MFL tools is the detection of metal loss, these tools have detected and identified deformations due to the combined effects of localized stresses/strains, damaged microstructure, and sensor liftoff which impact the signal recorded during an inspection. In some cases, a high-resolution MFL tool can detect deformations more effectively than standard caliper tools. (Batte, 2007)

A reported benefit of utilizing high-resolution MFL to detect deformations in place of caliper tools is that in certain situations MFL tools can be used to detect any metal loss associated with a deformation. Some MFL tools built for corrosion inspection have demonstrated incidental, but consistent, capabilities for identifying dents. (Rosenfeld, Pepper, and Leewis, 2002) MFL tools without sensor-displacement systems do not measure or report the depth of dents or deformations. In general, however, most ILI tool vendors and operators will run both caliper tools and MFL tools, combining the two inspection databases together in order to better detect, identify and characterize mechanical damage. This integration results in the ILI tool vendor’s ability to determine when a dent with metal loss occurs, as well as to allow for better sizing of dents.

Proximity to Welds

Anomalies or metallurgical differences at a weld generate a distinctive signal. As a result, some MFL tools can identify and determine the location of welds. In addition, MFL tools may detect trim associated with the seam weld/girth weld interface to determine seam location. Both can allow an analyst to determine whether mechanical damage is near a weld.

The ability to locate or detect the seam weld has decreased with some newer pipe. This is due, for example, to improvements in the cleanliness of pipe steels and the properties of ERW seam welds. While detection reliability has decreased, the need to identify the weld location in newer pipe is less critical due to the improved integrity of high-frequency ERW seams.

Metal Loss, Gouges, Cracks, and Other Anomalies

MFL tools are broadly recognized to have good to excellent detection and identification reliability for metal loss. The axial MFL detection thresholds for metal loss anomalies in the pipe body are typically 10 to 25 percent of the wall thickness. With circumferential MFL, the detection threshold can be as high as 50 percent of the wall thickness. The higher values are typically associated with seamless pipe and/or short defects. Above the depth thresholds, most inspection vendors report high probabilities of detection (90 to 95 percent or more). Some vendors claim to detect and report metal loss below these thresholds, but few include this capability in their performance specifications.

In one published report, an operator reported on a trial where an axial MFL tool was run through a line with 79 metal-loss defects. (Nestleroth) These metal-loss regions consisted of corrosion pits ranging in depth from 14 to 61 percent deep and corrosion patches from 11 to 52 percent deep. All metal-loss regions were detected, and no false calls were reported. A tool vendor reported on a program where 33 indications were investigated. (Nestleroth) All of the indications reported by the tool existed, and there were no false indications.

Metal-loss characterization accuracy for axial MFL is generally considered good for metal loss in the pipe body and away from dents. Typical performance specification for characterizing metal-loss depth with axial MFL is +/-10 percent of the wall thickness with 80 percent certainty. That is, the performance specifications say the depth will be reported within 10 percent of actual, 80 percent of the time. The sizing accuracy decreases for some defects, such as grooving or pitting. Here, performance specifications give characterization accuracies as large as +/-20 percent, with 80 percent certainty.

Independent analyses of actual performance generally confirm the claimed accuracies. See, for example, Barham, Brown, Fingerhut, and Porter, 2004; Desjardins, Reed, and Nickle, 2006; and Morrison et al. 2000.

Metal-loss characterization accuracy using circumferential MFL tools is considered less accurate than when using axial MFL tools. Typical claimed sizing accuracies are +/-15 percent or +/-20 percent, with 80 percent certainty. There are few published reports to support the claimed accuracies.

Dent detection is considered somewhat less reliable than metal loss detection. Most inspection companies do not claim to detect, identify, and characterize dents unless the inspection tool incorporates both displacement and MFL sensors.

Performance specifications often combine gouges with metal loss in claimed accuracies. Detection reliabilities are often stated with qualifiers, though, that restrict the claimed accuracies to gouges away from dents. Identification reliabilities, when given, are stated to be less than that for metal loss due to corrosion. That is, a vendor may claim to detect a gouge with high reliability but state that it may be identified as metal loss. For example, one MFL performance specification reviewed by the authors stated that gouges are properly identified between 50 and 90 percent of the time.

Depth characterization accuracy for gouges away from dents is sometimes assumed to be similar to that for metal loss due to corrosion. There are little published data to confirm this assumption. Characterization accuracies for gouges in dents are usually not claimed. In one paper, an inspection company stated that "Although detection of mechanical damage by MFL tools (alone) can be relatively straightforward, any attempt to quantify the size (depth and length) of the metal loss or to categorize the metal loss as being "significant" or "less significant" is speculative at best and is not usually attempted." (Olson, Pollard, and Putman, 2004)

Performance specifications for axial MFL tools do not generally include cracks. There is anecdotal evidence that axial MFL can detect and properly identify circumferential cracks when they open to the inner and/or outer pipe diameters. Some performance specifications for circumferential MFL tools claim capabilities related to cracking. These capabilities are generally restricted to open cracks with spacing between the crack faces. Axial and circumferential MFL tools are not usually considered capable of detecting or characterizing cracks in a gouge or dent.

Nearby defects can significantly affect signal interpretation and reduce the inspection capabilities discussed above. For example, the signal from corrosion metal loss near a gouge can overlap and overwhelm the signal from the gouge.

Finally, a caveat often claimed with respect to MFL and mechanical damage is that data analysis cannot reliably be performed using computer algorithms and instead must be performed by "the most experienced of data analysts." (Olsen, 2004)

Summary

Detection reliabilities for gouges are generally considered good unless the gouge is in a dent (most inspection vendors do not claim to reliably detect dents). Characterization accuracies for gouges away from dents and other defects are sometimes claimed to be the same as for metal loss due to corrosion, but there are little published data to support the claims. Characterization accuracies for gouges in dents are generally considered poor. The conversations that API 1163 requires of the users and the service providers fosters continuous improvement and acts to improve these performances.

6.2.4.3 Development Trends

In recent decades, there has been much development in MFL technology as related to mechanical damage. These developments range from improving the understanding of currently available tools to developing new tools. At the tool level, advances in data analysis have reportedly improved the ability to detect, identify, and characterize mechanical damage. Recent developments include using circumferential MFL, analyzing two or three components (axial, radial, circumferential) of the MFL signal rather than one (Co, Ironside, Ellis, and Wilkie, 2006), using multiple magnetization levels, and measuring the lift-off distance between the sensor heads and the pipe wall, etc.

In addition, fundamental and laboratory studies are underway to more fully understand MFL signals from mechanical damage (see, for example, Clapman, Babbar, and Rubinshteyn, 2004).

6.2.5 Ultrasonic Tools

6.2.5.1 Theory and Application

Ultrasonic technologies have been used to detect and measure geometric defects, such as dents, ovalities and wrinkles, and bore restrictions, without contacting the pipe wall in liquid filled pipelines where the liquid is the couplant. The distance between the fixed-position sensor and the pipe wall is determined by the timing of ultrasonic signals induced in the pipe wall and their reflections. Measurements are made relative to the center of the tool, and hence, any changes in the position of the tool relative to the center can affect the accuracy of measurements.

Most ultrasonic pigs work by sending a high-frequency sound wave toward the pipe wall and recording the echoes. A simple application is shown in Figure 6.4. The ultrasonic transducer sends a wave at right angle to the pipe wall. The sensor that sends the wave also measures its echoes. While a number of echoes can be produced, the most important are the reflections from the inner and outer pipe surfaces.

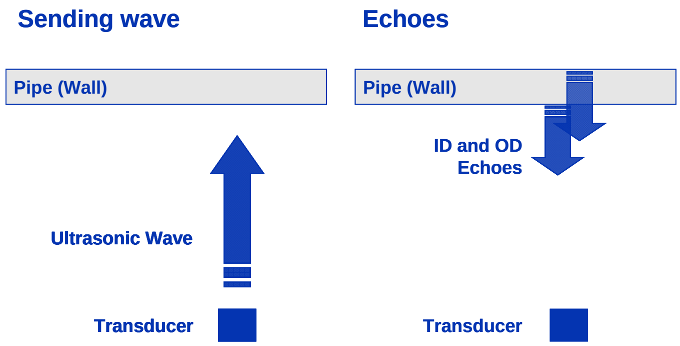

Figure 6.4. *Ultrasonic Wall Thickness Concept*

Dent depth is determined by the time between sending and receiving the ultrasonic wave. The time between the echoes from the inside and outside diameter is used to calculate the remaining wall thickness.

In wall thickness inspections, a compression wave is perpendicular to the pipe surface. When used for cracks, the transducer sends a shear ultrasonic wave an angle to the surface. Some of the wave is reflected away from the surface (and away from the sending transducer). The rest (the refracted wave) splits and enters the pipe steel. One of these two waves is used for inspection. When this wave reaches the outside wall, the process continues, moving around the pipe, "bouncing" or skipping between the inside and outside walls. See Figure 6.5.

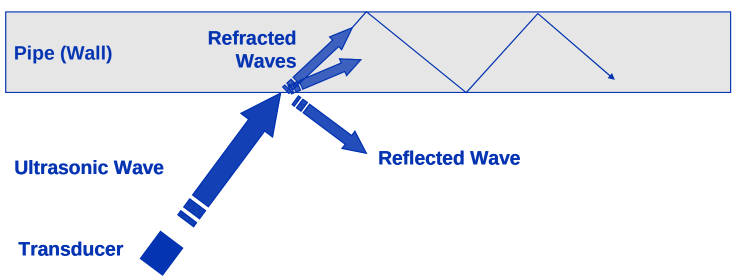

Figure 6.5. *Ultrasonic Shear Wave*

When an angled shear wave reaches a crack, some or all is reflected back to the sending transducer, which can then measure the echo. Using the same sensor to send and receive the ultrasonic wave in this way is referred to as "pulse-echo." The time between sending the wave and receiving an echo determines the distance to the crack, not its size. See Figure 6.6.

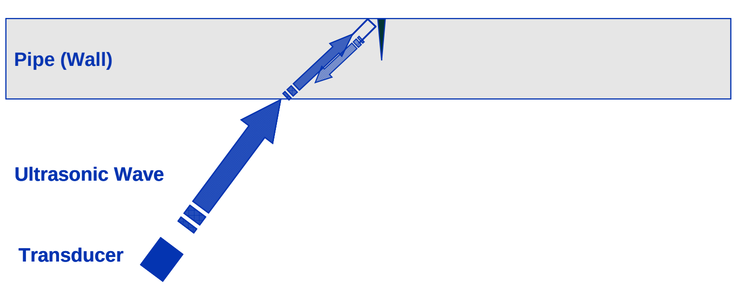

Figure 6.6. *Ultrasonic Wave Reflection from Crack*

Signal amplitude is sometimes used to characterize the crack depth with the pulse-echo approach, but this process is more complicated than determining the wall thickness. Factors that affect characterization include but are not limited to the depth and length of the crack, its angle to the pipe wall, the spacing between crack faces, the smoothness of the crack, the presence of other reflectors (possibly cracks), etc. Smooth, open, planar cracks that are perpendicular to the pipe wall are easiest to detect and size. Ultrasonic crack inspection can also be done in a "pitch-catch" mode. Here, a second transducer measures the signal that passes by the defect. The fraction of signal that reaches the second transducer is compared to the amount reflected back to the sending transducer to aid in detecting and sizing cracks.

There are a variety of other ways in which ultrasonic technologies have been implemented to detect and size anomalies slots in liquid and gas pipelines. These include but are not necessarily limited to:

- Wheel-Coupled Shear Wave Tools
- Phased-Array
- Electromagnetic Acoustic Transducers (EMATs)

In wheel-coupled tools, each wheel contains one or more transducers and is filled with a liquid couplant. This type of tool was developed to allow ultrasonic inspections of gas pipelines, when a couplant is not present. The wheels are staggered and transmit in both clockwise and counter-clockwise directions. Wheel size determines the number of transducers that can be accommodated around the circumference, which in turn limits the effectiveness of the tool to discriminate features. (Bubenik and Nestleroth, 2000; Rempel, 2005; Beller, 2006)

Phased-array crack detection tools operate largely as described above, except that the sending transducer produces a set of waves that have a range of angles to the pipe wall. By "sweeping" through a range of angles, the inspection systems are considered more sensitive to defects that are not perpendicular to the pipe wall. Gas transmission pipelines must be filled with water or other couplant for detection.

EMAT tools are fundamentally different from all of the methods described above in that the ultrasonic wave is generated in the pipe wall by pulsing an electromagnet system, and a liquid couplant is not required. The wave that is created is oriented in the same (circumferential) direction as the pipe surface. The pipeline acts as a waveguide, effectively channeling the waves as they move around the pipe. Theoretically, EMAT waves are more sensitive to defects that are perpendicular to the pipe wall.

(MSL, 2000; Terasen Pipelines, 2005; Reber and Beller, 2006; Selig and Leewis, 2006)

6.2.5.2 Detection, Identification, and Characterization Capabilities

Ultrasonic inspection systems have strengths and weaknesses that affect their ability to detect, identify, and characterize mechanical damage and other anomalies. Some factors are common to most compression beam and shear wave inspections, but not necessarily to EMAT inspections:

- Debris inside the pipe. Debris reflects ultrasonic waves, complicating detection, identification, and characterization.
- Inclusions and laminations in the pipe steel. Inclusions produce addition echoes. Laminations often reflect all of the ultrasonic wave, effectively making the area behind the lamination invisible.
- Surface roughness. Rough surfaces, especially at the inside diameter, scatter the ultrasonic waves, reducing the energy transmitted into and out of the pipe wall.
- Angle of the pipe surface to the ultrasonic wave. When the pipe surface is angled to the ultrasonic wave, as occurs in sharp metal loss, the index of refraction causes the beam to be reflected away from the transducers.

- Changes in pipe shape. Dents and other geometric anomalies also change the orientation of the ultrasonic wave to the pipe wall, changing the amount of wave transmitted into and out of the pipe wall. Shape changes also affect the path of ultrasonic reflections. For shear wave inspections that rely on multiple wave skips inside the pipe wall, the effect can be no detection.
- Tool speed. Ultrasonic inspection tools generally require enough time to fire all sensors and record the echoes. Typically, shear wave and EMAT ultrasonic tools require low tool velocities.
- Spacing of the transducers. The sensor spacing affects coverage and the extent to which individual waves can overlap.
- Electronics (e.g., sampling rate, dynamic range, and pulse repetition frequency). Sampling rates can be time or distance based. When using time-based sampling, problems with overlapping waves are minimized, but areas may be missed if the tool moves too quickly. Distance-based sampling ensures all areas are inspected at the risk of overlapping signals.
- Data storage. Ultrasonic inspections can produce orders or magnitude more data than MFL or caliper inspections. Even with very large storage devices, the data handling and storage requirements can be huge. Most or all ultrasonic crack-detection systems screen and/or compress the amount of data stored, which precludes a post-inspection analysis in areas where data were not stored.

Dents and Deformations

In theory, compression beam ultrasonic tools should detect, identify, and characterize dents and deformations. Shear wave tools may detect the inner surface, depending on its roughness curvature and other factors. When the tool detects and measures the inner surface, it should be able to identify and characterize dents. EMAT tools do not typically report dents or deformations.

Most ultrasonic specifications do not include a dent detection, identification, or characterization accuracy, and as with other inspection tools, it is hard to quantify actual performance with respect to dents.

Proximity to Welds

Seam and girth weld detection has not traditionally been a design requirement for ultrasonic tools. Nonetheless, some tools detect the welds as a result of an increase in wall thickness or weld anomalies. The reliability by which welds are detected is not well quantified.

Metal Loss, Gouges, Cracks, and Other Anomalies

Inner-surface mapping ultrasonic tools detect and size internal metal loss only. They are not sensitive to external metal loss, gouges, and cracks. The ability to detect and size internal metal loss is degraded in geometric anomalies, such as dents.

Ultrasonic compression beam tools are considered accurate in detecting, identifying, and characterizing both ID and OD metal loss (including gouges), provided the profile is not sharp. Detection thresholds are typically given as 0.01 to 0.1 inches (0.25 to 2.5 mm) in performance specifications. Ultrasonic wall thickness sizing accuracy is typically reported in absolute terms, rather than percent wall thickness for MFL. Typical performance specifications give depth tolerances as +/-0.012 to 0.020 inches (0.3 to 0.5 mm). For angled surfaces, and often in geometric anomalies, detection reliability and characterization accuracy drops as most of the return signal is focused away from the detector.

The performance specifications for ultrasonic shear wave tools do not usually provide separate detection thresholds and characterization accuracies for metal loss or gouges. For crack-like defects, the published detection and identification reliabilities vary, with degraded performance near geometric anomalies, such as dents. Published performance specifications typically give minimum detectible depth of 0.04 inches (1 mm) but do not address identification reliability. In one proprietary study dealing with crack detection in welds, the number of flaws reported was roughly equal to that missed.

Most or all shear-wave inspection tools report depths in bins, such as 10 to 25 percent of the wall thickness, but many published performance specifications do not give a depth sizing accuracy or certainty. In contracts with pipeline companies, a variety of claims are made. A typical value is that the correct depth bin is reported with a certainty of 80 percent. Characterization accuracy in dents or gouges is worse than elsewhere and is rarely specified.

Some inspection companies have begun to report crack-like depth in a percent wall thickness format, similar to that for metal loss with MFL tools. When reported in this fashion, the tolerance is typically large (e.g., +/-15 or 20 percent).

Regardless of how the depth is reported, there is little or no independent published data to evaluate actual sizing accuracy for shear-wave ultrasonic tools. In addition, when independent studies are done, there are significant questions regarding the accuracy of the field measurement tools. As a result, there is little basis for assessing actual performance.

The capabilities of wheeled ultrasonic tools are generally considered poorer than those of liquid- coupled tools, in part because there are fewer sensors around the circumference. One vendor's performance specification gives a detection threshold of 20 to 25 percent of the wall thickness, but does not list an identification reliability or depth characterization accuracy. There have been several published reports on the reliability and accuracy of wheeled ultrasonic tools.

Phased-array tools are reportedly more reliable than the wheeled or liquid-coupled tools at detecting and characterization crack-like anomalies that are not perpendicular to the pipe surface. Since phased-array tools are relatively new, field data demonstrating capabilities is just now being collected.

EMAT tools should be sensitive to metal loss and cracks, but real-world experience is sparse. One inspection vendor states "precision estimation model" in its performance specification for depth sizing. The same vendors give a minimum detectable depth of 0.04 inches (1 mm) in the base metal and 0.8 inches (2 mm) in the long seam.

Summary
Ultrasonic tools are considered to reliably detect greater amounts of metal loss in mechanical damage but are not believed to be as accurate or reliable when the damage is highly localized and abruptly introduced. Liquid-coupled UT can detect weld locations and can potentially locate mechanical damage within the weld.

6.2.5.3 Development Trends
Most ultrasonic tools are not designed to detect, identify, and characterize mechanical damage. The technologies used in the tools have significant and fundamental limitations in and near dents and they cannot address some damage features, such as cold-worked or deformed microstructures. Development efforts are underway to address some of these limitations. Some developments will increase the reliability with which metal loss or cracks are detected in dents, but sizing is expected to remain difficult.

Developments that combine MFL and ultrasonic sensors, or use both shear and compression wave ultrasonic sensors, are aimed at addressing the limitations discussed above. In theory, the performance should improve, but it is difficult to estimate the improvement now.

6.2.6 Other and Evolving Technologies
There are several other technologies currently under development or in commercial trials, which may be applicable in detecting, identifying and characterizing mechanical damage. Recent developments have

focused on ultrasonic and eddy current technologies. Basic principles and features are outlined below. For further information, see the references included.

6.2.6.1 Gas-Coupled Ultrasonics

Gas-coupled ultrasonic inspection systems are in the development stage. In most gas pipeline inspections, a large fraction of the ultrasonic wave is reflected at the inside diameter because of the index of refraction, and the amount entering the pipe may be too small to be of use. At higher pressures, a larger portion of the wave enters the pipe wall. Development efforts are aimed at using the wave to inspect for wall loss. If the methodology works for wall loss, it may be applicable to cracks or other defects related to mechanical damage. This type of tool must be sensitive to very small signals (echoes), since the wave fraction that enters and exits the pipe wall is small. Practical experience is lacking.

6.2.6.2 Eddy Currents

Eddy current inspection systems have been used to detect cracks in other industries for many years. Eddy currents are generated in a conductive material when the location or strength of a magnet field changes. Currents are produced naturally in a pipeline as an MFL tool moves down the line, or they can be generated by mechanically moving or pulsing an applied magnetic field.

Eddy currents have been used to detect cracks and other axially oriented defects in pipelines. (Silverwing, Accessed June 2007; Granillo and Moles, 2005; Physical Acoutics Corporation, Accessed June 2007; Koyama, Hoshikawa, and Taniyama, 2000)

Eddy current applications in pipelines are often limited by velocity, and performance degrades as the velocity increases. Eddy currents do not usually penetrate deep into the pipe wall. As a result, they are mostly applicable to defects on the near side (inside diameter). Remote field eddy current technology is a variation of standard eddy current testing and is meant to be sensitive to far side (outside diameter) defects. Much of the research on remote field eddy currents has been directed to finding SCC.

There is little or no data on actual performance of eddy current systems with respect to mechanical damage.

6.3 Aboveground Detection of Mechanical Damage

A number of mechanical damage defects have been detected by aboveground surveys, as used, for example, in External Corrosion Direct Assessment (ECDA) programs. While direct assessment programs occasionally locate mechanical damage when aligned and correlated with the pre-assessment observations, there is not a formalized direct assessment process for mechanical damage. Efforts such as this report, however, may be used in the future to advance the development of a mechanical damage direct assessment process.

All ECDA aboveground survey methods are designed to assess cathodic protection performance and/or to locate holidays in the pipeline coating. Holidays typically exist at mechanical damage defects, and a reliable holiday detection survey could be used to help find the defects. Some operators have reportedly used aboveground surveys to locate possible mechanical damage where prior right-of-way encroachment is suspected.

The following paragraphs briefly discuss aboveground ECDA surveys as related to mechanical damage.

6.3.1 Close-Interval Surveys

A cathodic protection system provides a current that is meant to prevent corrosion from taking place. Close interval surveys measure the potential between the pipe and a reference electrode at ground level. At a holiday, current is directed to the pipe, and a drop in potential can indicate a significant drain of cathodic protection current.

Close interval surveys are not normally used to detect coating holidays. Instead, they assess the effectiveness of the cathodic protection system. This type of survey would not reliably detect mechanical damage.

6.3.2 Voltage Gradient Surveys

Voltage gradient surveys are used to detect locations where current is flowing to the pipeline at a holiday. This type of survey is used to detect holidays that are large enough to affect the potential gradient at ground level. As such, they could detect mechanical damage if the holiday is large enough to affect the cathodic protection potential.

6.3.3 Current Mapping Surveys

Current mapping surveys use magnetometers or similar systems to detect or measure currents in the soil or pipe. Traditional current mapping applications measure an injected low frequency AC current in the pipe and are used to identify locations where a significant amount of current is leaving the pipe. Stray current applications are sensitive to currents in the soil and might be used to identify mechanical damage.

6.3.4 Conclusions on Aboveground Surveys

There are a variety of aboveground survey methods that could detect holidays due to mechanical damage, including but not limited to those discussed above. None of the above surveys can (currently) differentiate between mechanical damage and a holiday due to another cause. In addition, none will ever characterize or assess the severity of mechanical damage. Combinations have been successful locating small coating holidays.

Aboveground surveys are used today to manage cathodic protection systems. Criteria for evaluating anomalies are based on preventing or evaluating the likelihood of corrosion along the pipeline. Using aboveground surveys to detect mechanical damage would require different procedures and criteria for identifying possible damage than those used today. Such procedures and criteria do not (yet) exist.

6.4 In-the-Ditch Evaluations

In-the-ditch inspections can provide a more complete understanding of mechanical damage than ILI or the other methods discussed above. Many companies use nondestructive inspections and measurements to aid in determining whether a given defect requires repair. Others apply more basic guidelines, such as automatically repairing a dent that contains a gouge. Basic techniques used in the ditch and their ability to characterize mechanical damage are discussed below.

6.4.1 Dent Depth (Shape) Measurements

The most basic in-the-ditch method used to characterize mechanical damage is measurement of dent depth. Dent depth measurements are straightforward and can be as simple as identifying and measuring the deepest part of the dent. Errors in depth measurements result from several factors, such as debris on the external pipe surface. Differences in measured depths and those reported by ILI tools also occur due to re-rounding. Some re-rounding occurs in excavations from removal of overburden, but re-rounding does not occur in all cases. Large re-rounding can occur when, for example, rocks are removed at a dent site. Pressure in the pipe then pushes the indentation out, leaving a much smaller residual deformation. It is a known fact that re-rounding often results in micro cracks in the dent.

Sometimes, dent depth measurements are used in analyses to estimate the strains in the dent. In this case, it is common to grid and take measurements from a number of points on the pipe surface. This type of calculation requires accurate measurements from the points to characterize the local wall curvature. Evidence of kinking or rapid changes in curvature indicate that the damage is very localized, which can compromise the accuracy of strain calculations. In some cases, a simple template is all that is required to determine if the dent needs to be repaired. (see IPC 2006-10407)

Some laser mapping systems can be used to measure dent depths and shapes. These techniques are considered very accurate, provided that the pipe surface is clean.

6.4.2 Metal Loss Measurements

Identification and measurement of metal loss in a region of mechanical damage is needed for more detailed analyses. Measurements of metal loss due to gouging or movement of metal are performed in a manner similar to that of measurements of corrosion. To evaluate mechanical damage, especially when metal loss is abrupt, very detailed measurements are needed unless the damage is removed or repaired. Because this type of measurement is typically made relative to the external pipe surface, accuracy is affected in and around geometric changes (e.g., dents).

Once again, some laser mapping systems can be used to measure metal loss depths and profiles provided the pipe surface is clean.

6.4.3 Wall Thickness Measurements

Measurements of wall thickness in and around a dent or gouge provide information on pipe wall thinning, which can accompany some significant mechanical damage. Such measurements are typically checked using hand-held ultrasonic wall-thickness gauges. It is more difficult to obtain accurate measurements in areas where the geometry varies abruptly.

Various systems have been developed to map wall loss using eddy current and other types of sensors. These systems assume a constant wall thickness. UT thickness probes are needed to confirm the estimate. Field experience in the application of such techniques to characterize mechanical damage is limited.

6.4.4 Magnetic Particle Inspection

Magnetic Particle Inspection (MPI) is a commonly used technique for detecting cracks and other discontinuities in ferromagnetic materials. MPI reports linear indications but does not identify the underlying anomaly or flaw, which must be inferred or determined using other techniques. That is, MPI cannot, by itself, differentiate cracks due to re-rounding from those due to hook cracks, slivers, undercut, or possibly SCC.

Additional difficulties arise when using MPI near abrupt geometric discontinuities. For example, it is difficult to differentiate between the corners of a gouge and cracks at the corner. Where indications are seen away from sharp discontinuities, it is easier to infer they are "crack-like." Some operators consider the presence of a crack-like indication sufficient to justify a repair, in which case more detailed measurements are not made.

MPI does not measure crack depth, and inferences based on the size or thickness of the indication are considered approximate at best.

6.4.5 Dye Penetrant Inspection

Dye penetrant inspection is less commonly used to identify crack-like anomalies. While considered accurate at detecting cracks, such inspections are difficult to interpret on unpolished surfaces. They can contaminate the pipe surface, making recoating more difficult.

6.4.6 Etching and In-Situ Metallography

Changes to the microstructure due to mechanical damage are not typically detectible using any of the above field NDT techniques. Some operators use etching and visual magnification as a means of identifying microstructural damage that might occur, for example, in the metal below a gouge.

In-situ metallography, including the use of replicates, has been used with limited success to identify or differentiate the nature of cracks or linear indications. Proper training and application are considered necessary for reliable results.

6.4.7 Hardness Measurements

Changes in microstructure are often accompanied by changes in hardness, and equipment to measure hardness in the field has been available for a number of years. A limitation of field hardness measurements is that they are affected by surface preparation, cleanliness, and operator experience. In addition, these techniques typically measure hardness over a relatively large area.

Portable field hardness measurements are usually used in a relative sense – i.e., to compare hardness at one location to another. Attempts to quantify the degree of microstructural change are less successful.

6.4.8 Ultrasonic Shear Wave or Phased-Array Inspection

Ultrasonic shear wave and phased-array techniques are often used to estimate crack depth. These techniques, as in ILI tools, are strongly affected by the profile of the pipe wall in the vicinity of the measurements. They are also confounded by sharp geometric discontinuities and the presence of multiple cracks, which sometimes occurs in mechanical damage.

Ultrasonic techniques usually work best when the crack surface is flat and open. Tight cracks and cracks that branch are more difficult to accurately size.

6.4.9 Time-of-Flight Diffraction (TOFD)

Time-of-flight diffraction (TOFD) ultrasonic inspection is commonly used as a laboratory technique for determining the depth of cracks. TOFD relies on secondary waves that are generated by the crack tips. As with the other techniques discussed above, TOFD is sensitive to the dent and geometric anomalies present at most mechanical damage. (Terasen Pipelines, 2005; Beller, 2006; Teitsma, 2003, 2007; Trimborn, 1997)

6.4.10 Eddy Current Crack-Depth Measurements

There are a number of eddy current tools that have been used to measure crack depths. As with most other crack depth measurement techniques, the accuracy of the measurement is a function of many factors, including but not limited to surface cleanliness and sensor lift off. Eddy current crack depth measurements are also sensitive to crack opening type and the angle of the crack to the pipe surface. More accurate results obtained with cracks that are perpendicular to the surface and have large openings. Re-rounding cracks are commonly oriented at an angle to the pipe surface.

6.4.11 Grinding

Many operators use grinding to determine the depth of cracks detected by other inspection methods. This technique is sometimes considered helpful in differentiating whether an indication is a crack, mill defect, or (sometimes) SCC. Typically, grinding and MPI are alternated. After each grind, the remaining wall thickness is measured and the crack location mapped. After the crack disappears, the remaining wall thickness is used to determine the crack depth. Often, additional material is ground off after the crack disappears to ensure no microstructural damage remains.

Many operators consider grinding to be the most accurate method of determining crack depth, especially in mechanical damage. The remaining wall thickness can be treated as simple corrosion.

6.4.12 Summary of In-The-Ditch Techniques

The techniques summarized above provide insight into the nature and severity of mechanical damage, but no one technique addresses all aspects. Each nondestructive examination method discussed above relies substantially on the user's skill and technique to produce reliable and interpretable results. The more accurate measurements and inspections are typically more time consuming and expensive, which limits their use in the field.

The extent of in-the-ditch assessments varies by pipeline company, and many operators make repair decisions based on relatively simple measurements, such as dent profiling and MPI, and the requirements for defect assessment and repair under integrity management regulations. Also, since the cost of exposing the pipe to make detailed examinations may outweigh the cost of a repair, many operators automatically repair a pipe once it has been observed that there is mechanical damage of any extent.

6.5 Detection and Characterization Summary

This section identifies and summarizes some of the commonly used methods of detecting and characterizing mechanical damage, including ILI, aboveground surveys, and in-the-ditch measurements and inspections.

Many of the methods and types of equipment discussed here were developed to detect and characterize damage other than that produced by mechanical means. As a result, their effectiveness with respect to mechanical damage is reduced. In some cases, the techniques and equipment are effective only for subsets of mechanical damage, such as relatively smooth and plain dents.

The detection and identification reliability and characterization accuracy of ILI tools decrease as the complexity of the damage increases:

- Caliper or geometry tools are considered reliable at detecting and identifying dents over a detection threshold. Caliper and geometry tools are not used to detect, identify, or characterize metal loss, gouges, metallurgical damage, and cracks.
- MFL tools are considered reliable at detecting some dents and metal loss. The tools are thought to reliably detect but not necessarily properly identify and characterize larger amounts of metal loss in dents. This is especially true for damage that is highly localized and abrupt. Some MFL tools are being developed to detect and identify microstructural damage, but experience is limited. MFL tools have sometimes detected cracks, but their ability to do so with mechanical damage is largely suspect.
- Ultrasonic metal-loss tools are considered reliable at detecting, identifying, and characterizing dents and some gouges. Ultrasonic crack-detection tools have detected and characterized anomalies in welds and the pipe body. They are not generally considered reliable at detecting or

characterizing cracks in mechanical damage. Ultrasonic tools do not typically identify (differentiate) gouges from other forms of metal loss.

Some aboveground survey methods, such as voltage gradient surveys, are considered reliable at detecting coating damage when there is a suitable electrical path to the pipe surface. They can be useful in identifying mechanical damage where sufficient damage to the coating is present. For example, some operators use aboveground surveys to detect damage at locations where prior right-of-way encroachment is suspected. Aboveground surveys cannot determine the severity of mechanical damage.

In-the-ditch measurements are necessary to provide much more data on mechanical damage characteristics, but all of the techniques have limitations. Their application to obtain detailed information on the geometry and characteristics of mechanical damage can be time consuming. Commonly used method include, but are not limited to, MPI, ultrasonic wall thickness and shear wave inspections, and grinding to determine crack depth. Less commonly used methodologies that have promise with respect to mechanical damage include etching/in-situ metallography and portable (field) hardness testing. For crack sizing, potentially useful methodologies include time of flight diffraction, eddy current testing, and laser UT crack depth measurement.

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7 Assessment

7.1 Introduction and Overview

7.1.1 Scope

This section provides a review and commentary on methods to analyze mechanical damage. There are many factors that can precipitate damage to a pipeline, such as situational threats imposed by the particular geographic location of the system (for example, location in a densely populated area, which increases the threat of third-party intervention), the manner in which the pipe's metallurgical properties respond to damage, and potential mishaps during pipe manufacture, transport, and/or installation. Consequently, mechanical damage is manifested in many forms. In addition, a pipeline's operating, maintenance, and examination history can all serve as predictors of pipe susceptibility to mechanical damage and the severity of damage.

There are compelling reasons to scientifically investigate mechanical damage. In addition to gaining a clearer understanding of the factors that can lead to short- and long-term pipe failure and the form in which the damage will likely be manifest (for example, as a leak or a rupture), researching mechanical damage enables investigators to better evaluate the relative safety and effectiveness of current and proposed damage prevention, assessment, and mitigation measures.

This section discusses currently employed or accepted methods of assessing the impact of mechanical damage on the serviceability of a pipeline, including methods presented in current national and international guidance and standards. However, no recommendations for the use of a particular technology are offered.

7.1.2 History of Model Development

Assessment models have been developed to address various aspects of mechanical damage. Some models consider whether a given impact scenario will lead to a puncture. Others address factors such as re-rounding, local stress concentrations, and load-deflection behavior. This subsection provides a history of model development and introduces many of the models currently in use.

Studies concerning the behavior of damaged pipe and the development of models for assessing damage severity commenced in the United States and Europe in the 1950s and have continued to the present day. Much of the early work focused on the development of empirical models based on experimental results and was conducted by Battelle (sponsored by the American Gas Association [AGA] and Pipeline Research Council International [PRCI]), British Gas, Gaz de France, and others. Later work was coordinated by PRCI, Gas Research Institute (GRI), European Pipeline Research Group (EPRG), American Petroleum Institute (API) and CANMET, and more recently by the U.S. Department of Transportation /Pipeline and Hazardous Materials Safety Administration (PHMSA). Several individual companies in North America, Europe, and Japan have also undertaken and published studies.

More than 400 full-scale tests (some performed on pipe lengths and some on ring sections) have been completed to evaluate a wide range of pipe geometries, pipe grades, damage configurations, and depths. The results of the tests have been collated and reviewed in depth in publications by GRI (1999), PRCI (2003), EPRG (1999), and others. Cosham and Hopkins (2002, 2003, and 2004) reviewed data and analyses on behalf of the Joint Industry Group responsible for developing the *Pipeline Defect Assessment Manual*. The reader is directed to these documents for in-depth analysis of the test results and their implications.

Most of the "basic" models available today are essentially empirical descriptions or best approximations of behavior extrapolated from tests and/or data from actual experience on in-service pipelines. These models usually characterize damage in simple terms, such as a "plain dent," "gouge," or "dent-gouge." Simple models assess damage in terms of dent, gouge, or crack depth in conjunction with other geometric (D, t, or axial length of damage) and material (Specified Minimum Yield Strength [SMYS] or Ultimate Tensile Strength [UTS]) parameters.

"Intermediate level" models add mechanics-derived formulations to improve failure predictions. These models, which also incorporate geometric and material parameters, are based on understandings of the fundamental processes of deformation, crack formation and growth, and failure due to plastic instability or fracture. Such formulations are used to reduce the empiricism of basic analyses.

"Advanced" models are based primarily on the principles of mechanics, with test data and experience used to calibrate or enhance confidence in failure predictions. These models typically describe the characteristics and behavior of damage, as well as the overall process leading to pipe failure. Development of these models may entail one or more of the following:

- Modeling of load and deformation behavior during denting and re-rounding
- Modeling of the stress and strain distributions arising from denting and re-rounding
- Modeling of crack development by stable tearing under sustained or intermittently changing pressure
- Modeling of crack development by fatigue due to pressure cycling
- Modeling of puncture resistance

Depending upon their complexity, intermediate and advanced models usually require an in-depth understanding of how properties such as stress-strain behavior, tearing resistance, toughness, and ductility are changed by the deformation during denting and re-rounding. Consequently, some of these models are more suitable for specialized research applications than for general use.

Despite the large amount of effort expended, there is still considerable uncertainty concerning the efforts to model mechanical damage and the reliability of the predictive models. The situation has been made more complex by the wide variety of simulated damage and loading conditions studied in individual test programs, and by the lack of supporting information concerning the properties of the pipe material and how they are changed by the damage.

The following sections describe various models that have proven useful in understanding mechanical damage and its severity.

7.2 Damage Models

7.2.1 Deformation and Re-Rounding

The process of introducing a dent into a pipeline involves both elastic and plastic deformation. When the indenter is removed, the dent will generally spring back. Re-rounding can be elastic (no permanent change in the dent depth) or plastic (a permanent reduction in the dent depth). Spring-back and re-rounding behavior depend on pipe geometry, material properties, operating pressure, pipeline external support stiffness, and dent shape.

Numerical studies of deformation and re-rounding behavior commenced in the 1980s, and were continued by Battelle and others. (Leis and Hopkins, 2003; Cosham and Hopkins, 2004; Leis and Francini, 1999) Non-linear deformation model predictions were compared to experimental data (Figure 7.1), showing generally good agreement. The results were used to model the relationship between initial dent depth and residual dent depth (Figure 7.2) and to study residual strains in the vicinity of the dent (Figure 7.3).

Figure 7.1 shows a typical load-displacement (dent depth) during and after denting a pressurized pipe. As a load is increased, the dent depth increases, reaching a maximum at the maximum load. As the load (indenter) is removed, the dent rebounds in a nonlinear fashion, and there is a residual dent depth after the load drops to zero.

Similar analyses indicate that strains and deformation characteristics are determined by the shape of the indenter, the manner in which the indenter is applied, and the material properties of the pipe. The area of contact grows from the center of the dent as its depth increases. The resulting strain distribution also depends on the strain hardening of the pipe and on the friction forces between the pipe and the indenter. The relationship between strain and displacement is complex and non-linear, and the site of maximum damage may not be the deepest point of the dent.

Figure 7.3 shows that outer-surface strains under an indenting device are predominantly compressive (negative). (The strains at the inner surface are tensile.) The curves, which represent three different strain hardening (n) components, all start at a tensile (positive) strain, associated with the pressurizing of a pipe.

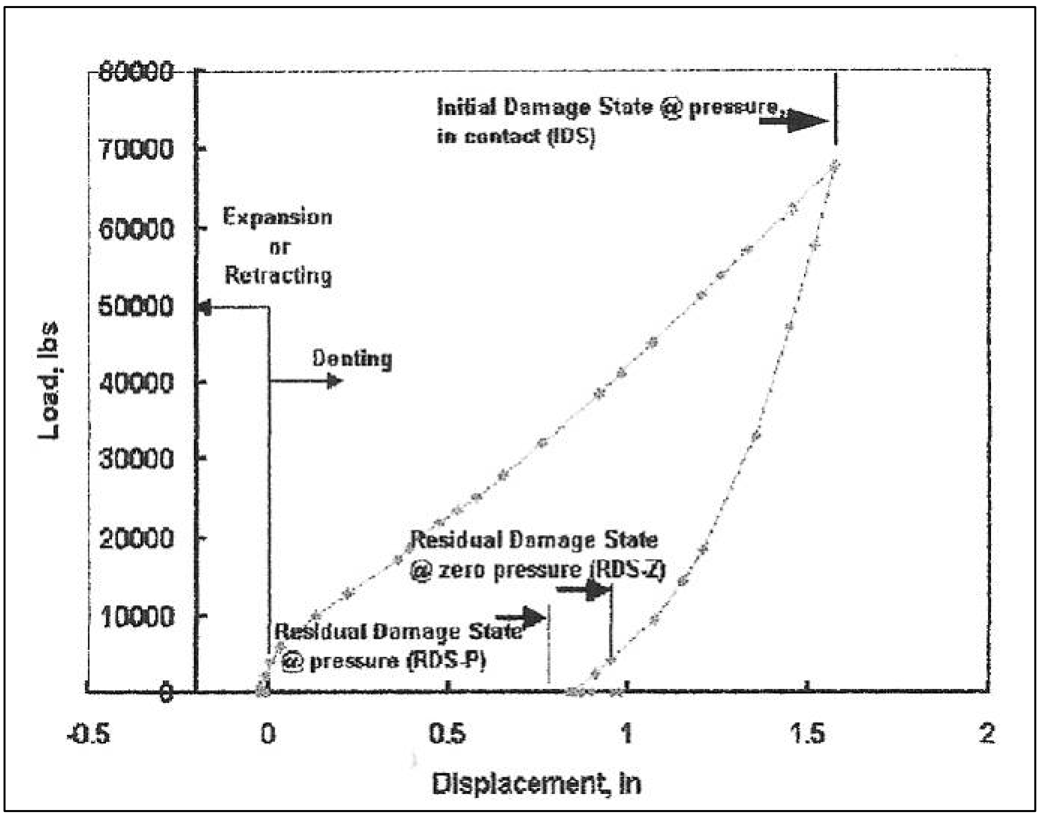


Figure 7.1 – Validation of Predicted Load-Deformation Behavior During Denting and Re-Rounding (Leis and Hopkins, 2003)

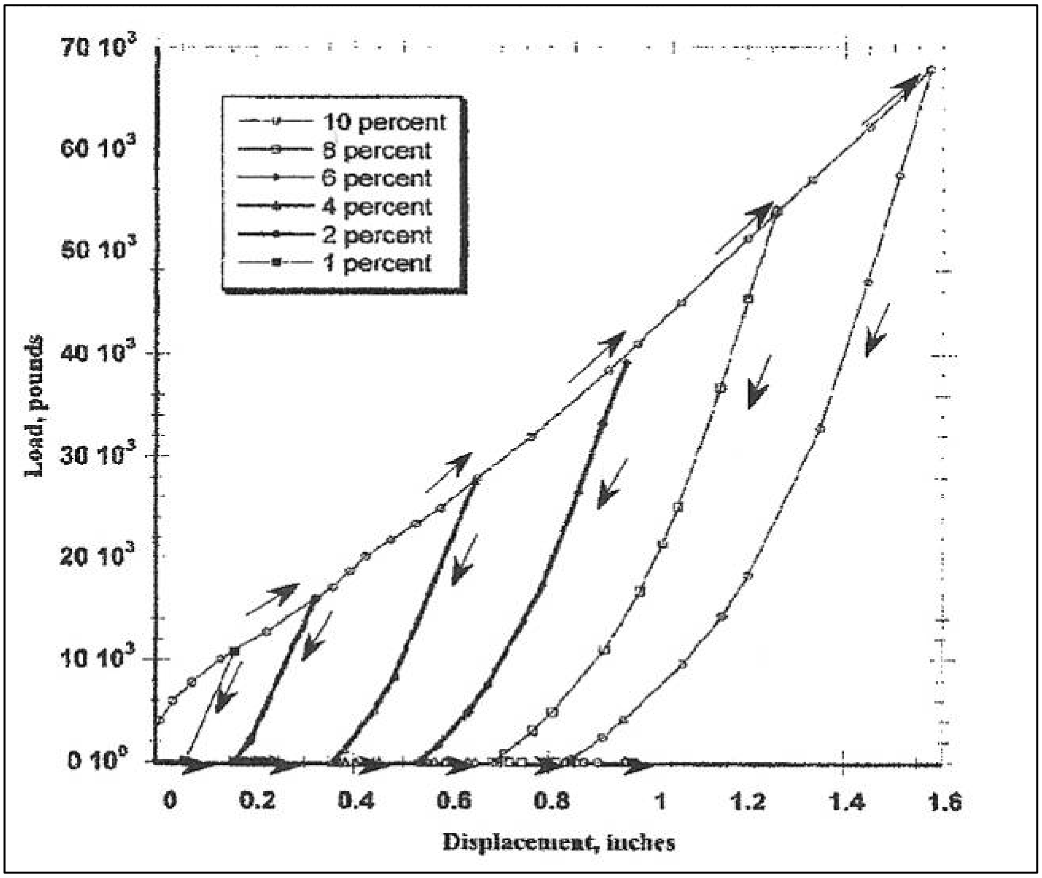


Figure 7.2 – Effect of Initial Dent Depth on Load-Displacement Behavior During Denting and Re-Rounding (Leis and Hopkins, 2003)

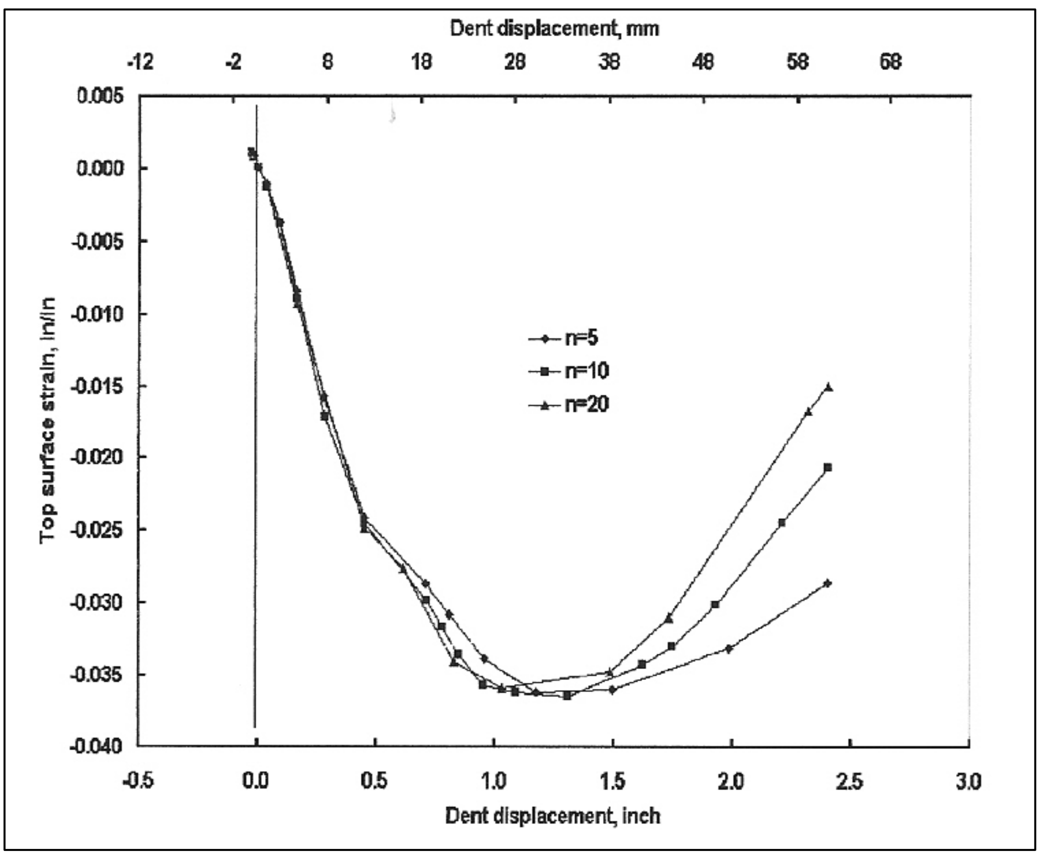


Figure 7.3 – Non-Linear Relationships Between Strain and Displacement at the Outside Centre of a Dent, During Denting to 8% of the Pipe Diameter (Leis and Hopkins, 2003)

7.2.2 Residual Dent Depth

Leis and Hopkins (2003) and Cosham and Hopkins (2004) reviewed methods of calculating spring-back and re-rounding developed by Battelle, EPRG, and others. All of the methods are limited and show considerable scatter when compared to the experimental data. They generally agree with the revised EPRG factor in evaluating re-rounding in plain dents, which is recommended in the Pipeline Defect Assessment Manual:

$$H0/D = 1.43Hr/D \qquad \text{Equation (1)}$$

where H_0 is the equivalent dent depth at zero pressure, Hr is the dent depth remaining after damage (after spring-back), and D is the outside diameter of the pipe.

Leis and Hopkins (2003) indicate that re-rounding, localized stretching, and wall-thinning can lead to localized bulging and promotes shear cracking. A long dent springs back and re-rounds to a greater extent than a short dent, and the re-rounding tends to occur more often in the middle than at the ends of the dent. Smooth dents are more likely to spring back and re-round than are dents that contain sharp contours (e.g., kinked dents). Spring-back and re-rounding behavior is more pronounced in thin-walled pipes than in thick-walled pipes.

7.2.3 Stresses and Strains

Recent editions of ASME B31.8 provide guidelines for assessing strain fields around dents. It should be noted that the equations in the 2003 Edition of ASME B31.8 that describe a simplified strain criterion contain errors (which have been corrected in the 2007 Edition). The equations are correctly written as:

$$\varepsilon 1 = t\,(1/R0-1/R1)/2 \qquad \text{Equation (2)}$$

where ε1 is the estimated circumferential strain, t is the pipe wall thickness, R0 is the original outside radius, and R1 is the indented radius at the outside surface of the pipe (the measurements are made after excavation, and so are subject to any re-rounding and depressurization that might have occurred).

The calculation of longitudinal strain is essentially similar, but there are additional strain contributions due to the longitudinal stretching of the material in the dent:

$$\varepsilon_2 = -0.5t/R_2 \qquad \text{Equation (3)}$$
$$\varepsilon_3 = 0.5(d/L)^2 \qquad \text{Equation (4)}$$

where ε_2 is the estimated longitudinal bending strain, ε_3 is the estimated strain from elongation, R_2 is the radius measured along meridian through the dent at the outside surface of the pipe, d is the dent depth, and L is the dent length.

The resultant strains on the inside and outside pipe surfaces are computed as:

$$\text{Inside surface} \quad \varepsilon_i = [\varepsilon_1\, 2 - \varepsilon_1(\varepsilon_2+\varepsilon_3) + (\varepsilon_2+\varepsilon_3)^2]1/2 \qquad \text{Equation (5)}$$

and,

$$\text{Outside surface} \quad \varepsilon_o = [\varepsilon_1^2 + \varepsilon 1(-\varepsilon_2+\varepsilon_3) + (-\varepsilon_2+\varepsilon_3)^2]1/2 \qquad \text{Equation (6)}$$

Acceptance is established by comparing an estimated strain with a suitable strain criterion; the ASME criterion is six percent. Moreover, some practitioners are applying higher allowable strain limits tied to specified or known material strain capacity in conjunction with more accurate estimates of local strain of deformation than what the above equations may represent. Note that work on appropriate methods for estimating and combining strains of deformation, and suitable strain criteria, continues. It is foreseeable that higher strain allowances tied to the specified tensile strain capacity of the material will be recognized in conjunction with improved approaches to estimating strain.

The rationale for considering strain in this context is two-fold. First, it has been observed that cracks or penetrations that may be a cause for concern have occurred in relatively acute dents whose depths nonetheless meet traditional dent depth-based safety acceptance criteria, while other relatively deeper indentations (usually spread out over large areas of the pipe surface) often do not contain cracks or penetrations that pose a significant threat. Second, strain can be used to evaluate the likelihood of metal damage, if quantified and compared to a suitable criterion, such as strain at fracture reduced by a suitable factor of safety, thereby providing a more meaningful estimation of dent severity than dent depth alone. It is intuitive that for a given dent depth, the dent strain will increase if the wall thickness is increased or if the local dent radius is decreased.

In recent years, there have been considerable advances in 3-D finite element modeling, including the use of methods incorporating large strains. Such methods have enabled comprehensive descriptions of the stresses and strains during denting, re-rounding, and subsequent operational loading, and have extended and corroborated the earlier numerical analyses, e.g., Figure 7.4, from Ironside and Carroll (2002).

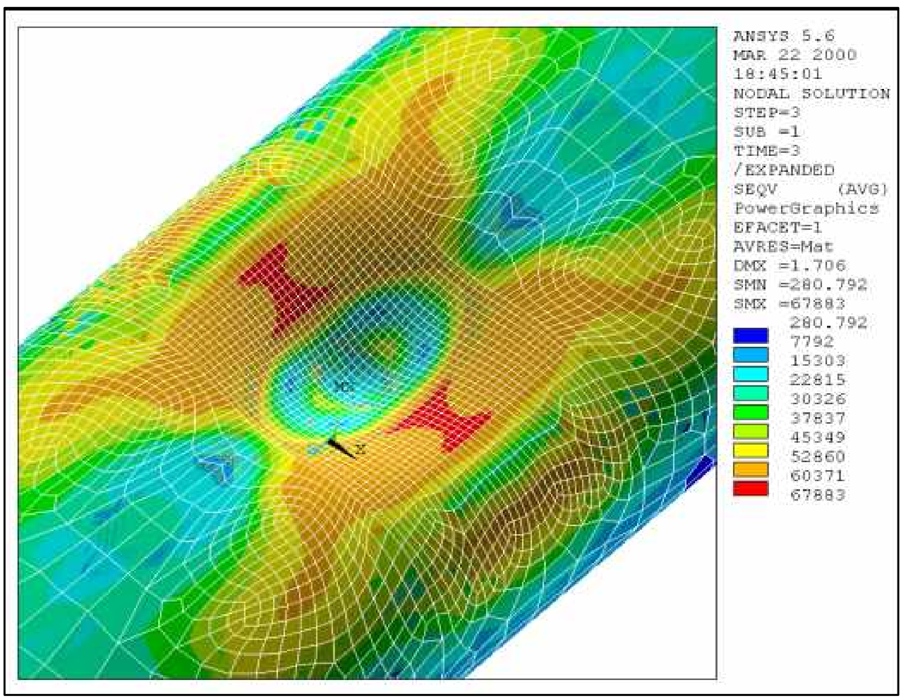


Figure 7.4 – Finite Element Model of Stress Distribution Around a Re-Rounded Dent (Ironside and Carroll, 2002)

However, again, the utility of such models has been limited by the lack of accurate information describing pipe material properties during deformation – particularly strain-hardening behavior during loading and unloading. In addition, as yet there is no established means of representing within the finite element model the conditions required to evaluate fracture initiation and crack extension. Consequently, while finite element modeling has been useful in gaining an understanding of deformation behavior, it has not been readily applicable to modeling and predicting the failure behavior of damaged pipes. As with the other models and techniques reviewed in this chapter, finite element modeling also relies on several assumptions that in many cases are based on unknown conditions or otherwise unsubstantiated information. A final barrier to routine application is that Finite Element Analysis (FEA) is not readily applied case-by-case to the rapid assessment of damage features in large numbers.

7.2.4 Plain Dents – Burst

Early research revealed that a plain, unrestrained dent as deep as 10 percent of a pipe's diameter did not reduce pipe pressure-containment capacity (GRI, 1999; Leis and Hopkins, 2003). Based on a review of more than 70 pressure tests on dented pipe samples, and taking into account the possible effects of re-rounding, EPRG concluded that all plain dents less than seven percent deep could safely be allowed to remain. This conclusion is further substantiated (Leis and Hopkins, 2003; Cosham and Hopkins, 2004) by the results of other published full-scale pipe tests (Figure 7.5).

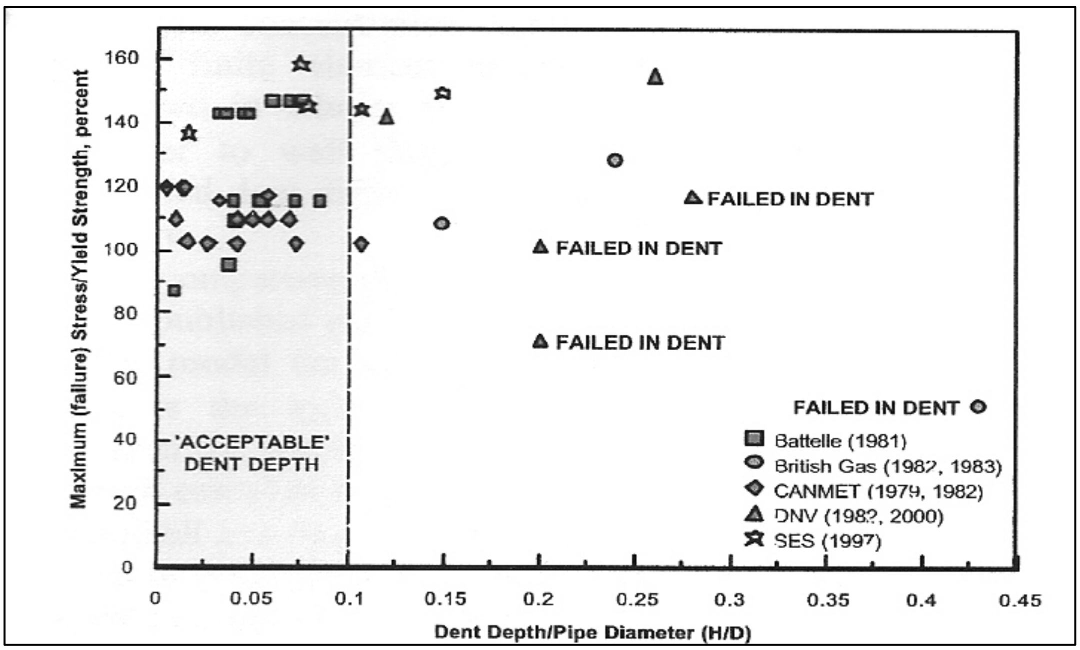


Figure 7.5 – Failure Behavior in Full-Scale Tests on Plain Dents (Cosham and Hopkins, 2004)

Safety thresholds of six percent depth or six percent strain have been established for plain dents and dents with metal-loss corrosion. A pipeline with a dent whose depth or strain level falls below the safety threshold is not considered at risk for bursting or delayed failure, provided that the pipeline does not undergo unusually severe pressure cycling. It is coincidental that six percent is the threshold for both depth and strain severity. Historically, the depth criterion was based on the tolerance for accommodate pigging. The strain criterion was based on one-half of the lowest degree of strain at which one might expect cracking to occur. Cracks have been observed in buckles at strain levels greater than 12 percent, so a six percent guideline was established to provide a margin of safety. In comparison, field bends tend to impose a strain of three percent on a pipe without negative impacts, and welds are typically qualified to support strain levels of up to 10 percent. Test data to substantiate these figures are presented in Figure 7.6.

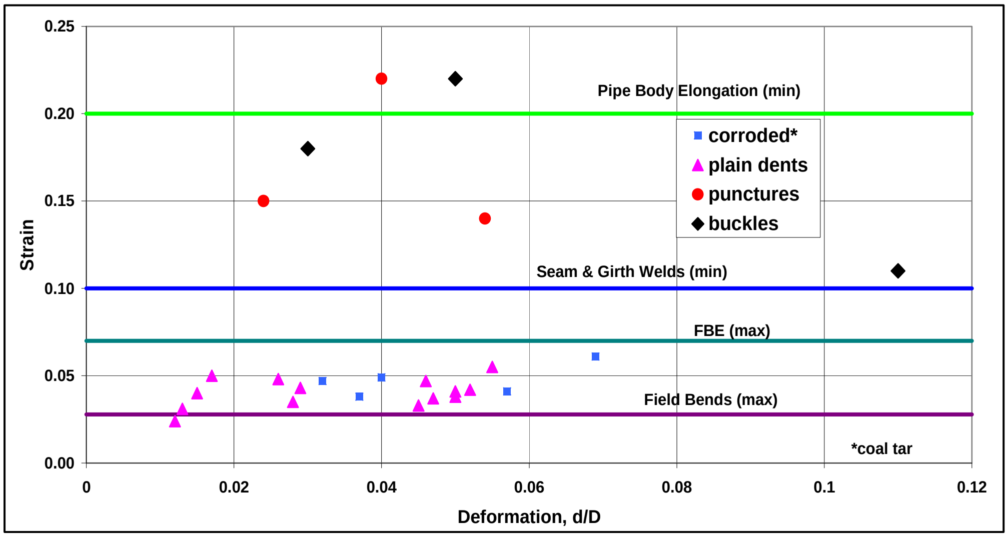


Figure 7.6 – Observed Relationship Between Strain Component, Degree of Damage, and Dent Depth (Rosenfeld, Pepper, and Leewis, 2002)

7.2.5 Plain Dents – Fatigue

Plain dents may decrease the fatigue life of pipes subjected to cyclic loading over a long period of time (Rosenfeld et al., 2002; API 1156, 1997; Ironside and Carroll, 2002; Baker, Jr., M., 2004). In the development of their Dent Assessment Model, Dinovitzer et al. (2002) have documented the effects of dent depth severity on fatigue life (Figure 7.7 through Figure 7.10). In addition, they have considered the effect of indenter shape on the fatigue life of the damaged pipe. The findings presented in the figures below enable several generalizations to be made. Note that these data are case specific and subject to the assumptions and tests established for this particular type of analysis.

Figure 7.7 illustrates the relationship between cycles to fatigue failure and the D/t ratio for both spherical and cylindrical indenters at different depths. In all cases, the fatigue life reduces with a decrease in D/t ratio, i.e., a smaller-diameter, thicker-walled pipe is more susceptible to fatigue problems following denting than is a larger-diameter, thinner-walled pipe. (This can be somewhat misleading as operating experience seems to show that pipe with larger D/t is more susceptible to long-term integrity concerns with dent-like deformations. The explanation for this apparent inconsistency may be that the heavier-wall, low-D/t pipe is more resistant to the formation of deep dents to start with and thus experiences fewer long-term integrity concerns.) In addition, the plot indicates that a cylindrical indenter reduces pipe fatigue life to a greater extent than does a spherical indenter. This is due to the differences in constraint around a short or long dent.

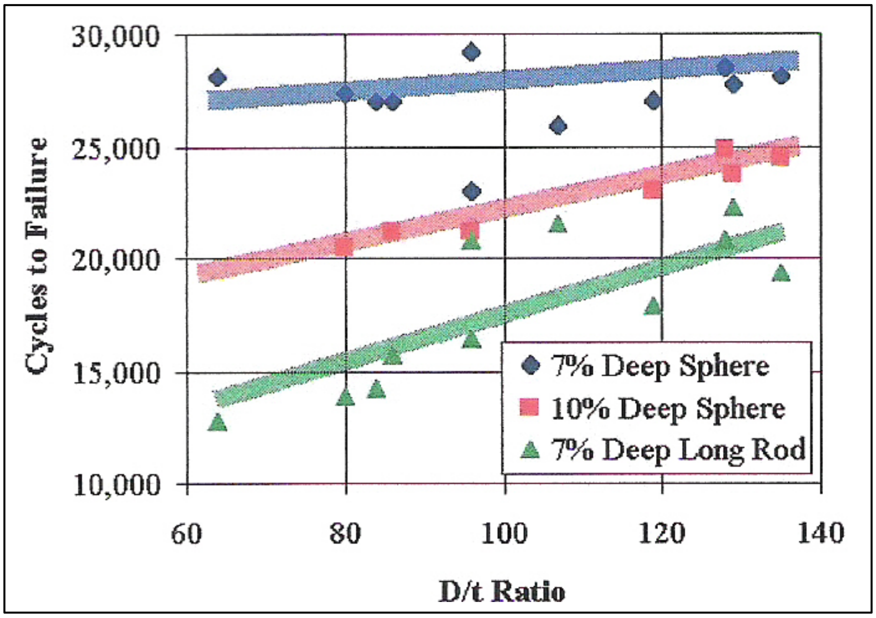


Figure 7.7 – Effect of D/t Ratio and Damage Type on the Fatigue Life of Plain Dents (Dinovitzer et al.,2002)

Figure 7.8 shows the relationship between cycles to failure and dent depth ratio. The data are somewhat limited, but indicate that as the dent depth ratio increases, pipe fatigue life decreases. Furthermore, pipe fatigue life is significantly reduced as dent depth severity reaches one percent, but there is no further reduction if dent severity is increased to four percent. A dent of approximately one percent or more can reduce fatigue life by more than five times.

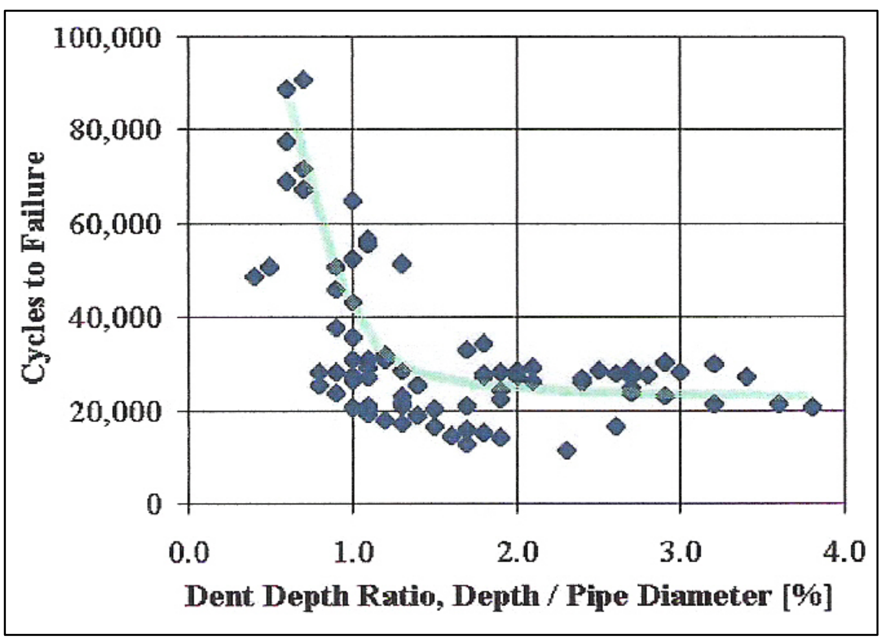


Figure 7.8 – Effect of Dent Depth on Fatigue Life of Plain Dents (Dinovitzer et al.,2002)

Figure 7.10 shows the effect of dent profiles, as viewed in the transverse (circumferential) direction, on the fatigue life of the pipe. Generally, the data indicate that an increase in shoulder slope and notch lead to an improvement in fatigue life.

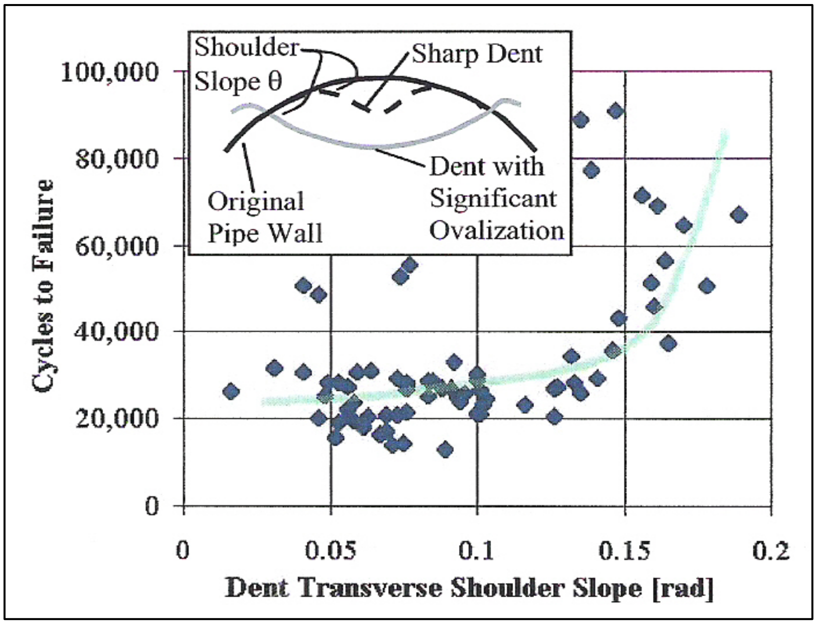


Figure 7.9 – Effect of Dent Profile on Fatigue Life of Plain Dents (Dinovitzer et al.,2002)

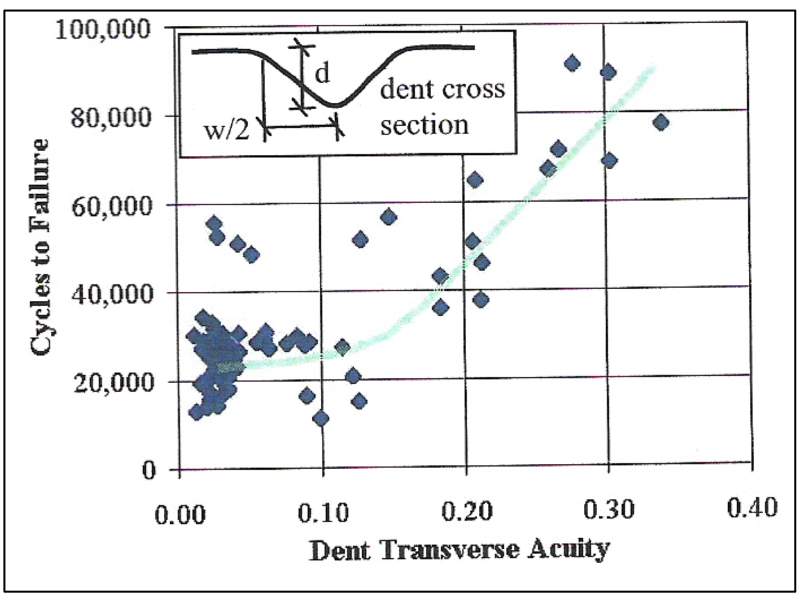


Figure 7.10 – Effect of Acuity (w/2d) on the Fatigue Life of Plain Dents (Dinovitzer et al., 2002)

In a recent review, Rosenfeld studied fatigue performance and reported that it is influenced by initial dent depth and width-to-depth ratio, pipe geometry (D/t) and grade, mean pressure, and cyclic pressure range. Tests showed that unrestrained plain dents with depths that occupy two percent or less of the pipe diameter exhibited a fatigue life of between 100,000 and 1,000,000 cycles, when cycled at a stress range between 36 percent and 72 percent of SMYS. Bood (1999) documented similar effects, from which it developed a model and equation that accounted for the influence of initial dent depth, dent shape, material strength, mean pressure, and cyclic pressure range. Results indicated that dent depths up to four percent of pipe diameter reduced pipe fatigue life by nearly 10 times (Figure 7.11).

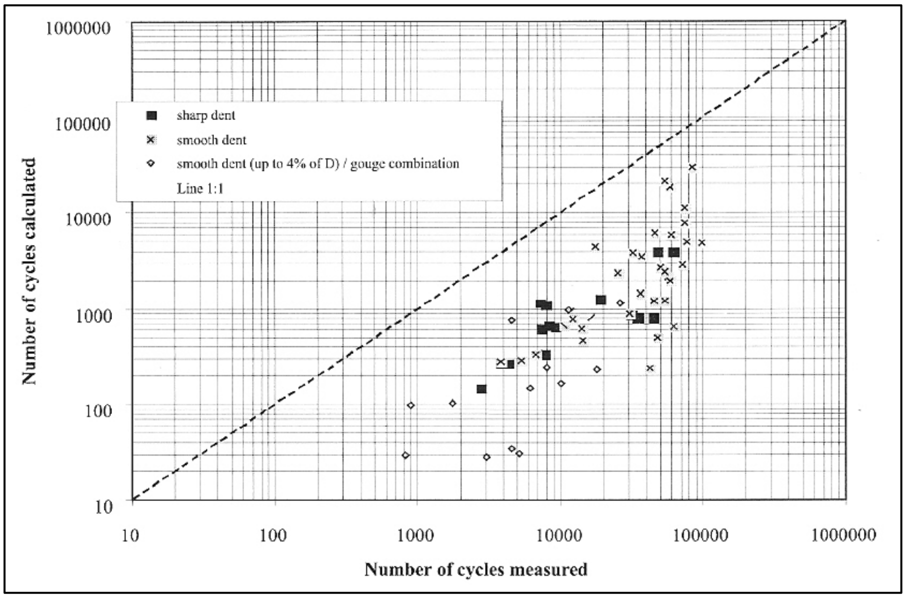
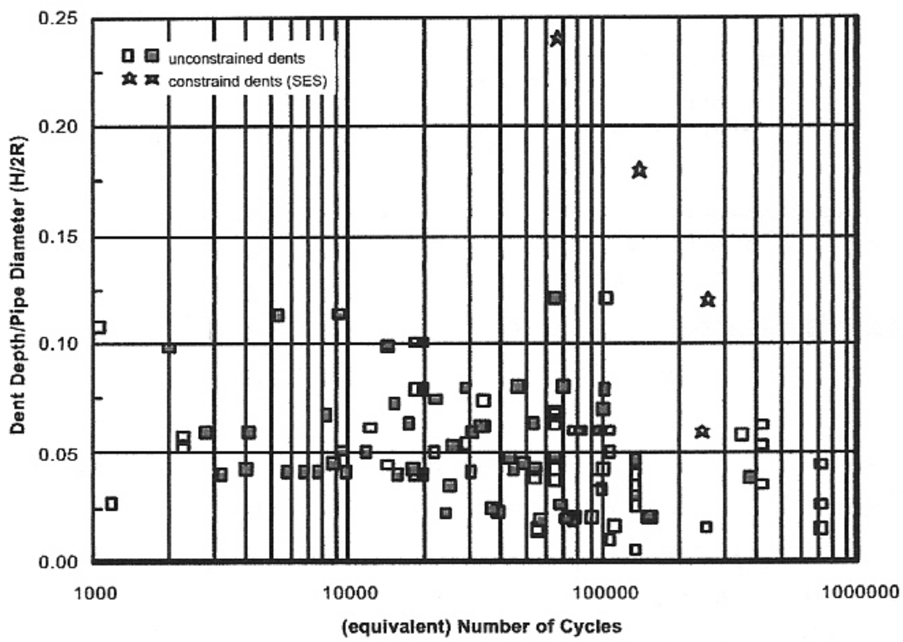


Figure 7.11 – Comparison of Measured and Calculated Dent Fatigue Life, Including an Adjustment Factor of 10 on Predicted Fatigue Life (EPRG, 1999)

The results described above do not address the effect of axial length of the dent. Other researchers (Leis and Hopkins, 2003; Ironside and Carroll, 2002; Rinehart and Keating, 2002) have shown that long dents, which can experience greater re-rounding and center cracking, can exhibit significantly shorter fatigue lives than shorter dents that are similar in all other respects. This was demonstrated earlier in Figure 7.7.

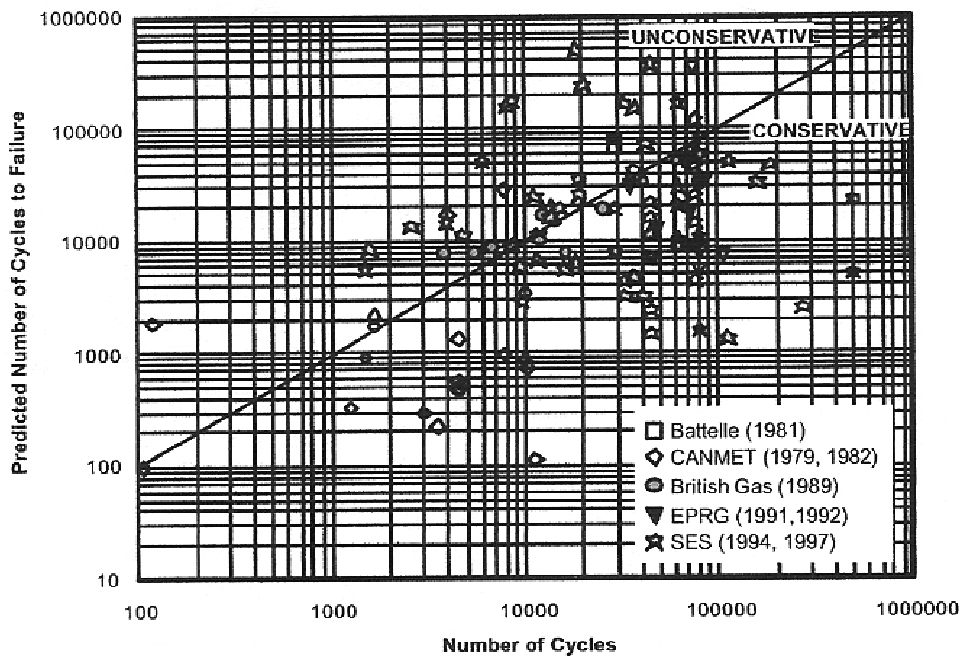
Restrained plain dents have been reported (Rosenfeld et al., 2002; API 1156, 1997) to have a fatigue life of at least one order of magnitude greater than unrestrained plain dents of the same size and shape (Figure 7.12), primarily because of the reduced cyclic load. However, the experimental data required to confirm this finding tends to demonstrate a high degree of scatter, and therefore, the conclusion should be regarded as tentative.



Note: In this figure, open symbols (e.g. ○) denote tests that did not fail during the test (the test was terminated prior to failure) and closed symbols (e.g. ●) denote tests that did fail during the test.

Figure 7.12 – Fatigue Lives of Constrained and Unconstrained Plain Dents (Cosham and Hopkins, 2004)

Cosham and Hopkins (2004) reviewed several published models for predicting the fatigue life of a plain dent, including those developed by EPRG and Stress Engineering Services (SES). They concluded that the EPRG model yielded more accurate overall predictions than the SES model (Figure 7.13), although considerable scatter occurred with both models.



Note: In this figure, open symbols (e.g. O) denote tests that did not fail during the test (the test was terminated prior to failure) and closed symbols (e.g. ●) denote tests that did fail during the test.

Figure 7.13 – Predictions of the Fatigue Life of Plain Dents using the EPRG Model (Cosham and Hopkins, 2004)

Rosenfeld et al. (2002) and others (Ironside and Carroll, 2002) have pointed out that if two or more restrained dents are in proximity (located within the distance of one pipe diameter to each other, and commonly referred to as double-centered dents), the intervening pipe wall, which may actually be flattened or saddle-shaped, is in effect unrestrained and able to flex in response to pressure cycling. Such situations have only been addressed on a case-by-case basis and are primarily an issue on liquid pipelines owing to their more aggressive pressure-cycle operation. However, double-centered dents would generally be assumed to present a higher risk than other rock dents, even in gas pipelines.

7.2.6 Dents at Welds

The reviews by (API 1156 – 1997, Leis & Hopkins – 2003, Cosham & Hopkins – 2004, Baker Report TTO 10 – 2004) identify only 18 tests that have been completed on dents associated with welds. The results suggest that dents at welds could reduce the burst pressure, especially if weld flaws exist. A general conclusion is that, if the weld quality is satisfactory, burst pressure is reduced only for deep dents. This conclusion forms the basis for EPRG and PRCI guidance (see later section).

Fatigue tests on pipe rings containing dented seam welds have shown that fatigue life can be reduced by as much as a factor of 10 compared to that of undented seamless pipe, but, again, the effect depends to a large extent on the quality of the weld.

The above results refer to dents superimposed on welds. Other work (Dinovitzer, 2006) has confirmed that, in some instances, while the stress fields associated with dents extend for several pipe diameters from the dent center, the dent fatigue life is only reduced if the weld is within the region of inward radial deflection.

7.2.7 Burst Behavior of Gouges

A gouge or metal-loss defect occurs when the indenter moves or removes metal from the pipe wall. The material that has been in contact with the indenter will have been severely deformed and may contain surface cracking transverse to the direction of gouging.

Cosham and Hopkins (2002) performed an in-depth review of the burst testing and evaluation of gouges undertaken by Battelle and others. They identified 190 published burst tests that form the basis of the models describing gouge behavior. Pipe damage had been introduced in different ways and the tests were performed under different experimental conditions, so direct comparisons are difficult. However, some generalizations can be made. They found that the NG-18 part-wall failure criterion developed originally by Battelle gave the best description of the burst pressure in full-scale tests on axially oriented gouges (Figure 7.14). Several forms of the equation have been developed that incorporate different expressions for the Folias factor, which accounts for the stress concentration due to bulging. However, there is little difference among the equations in overall accuracy to predict burst pressure.

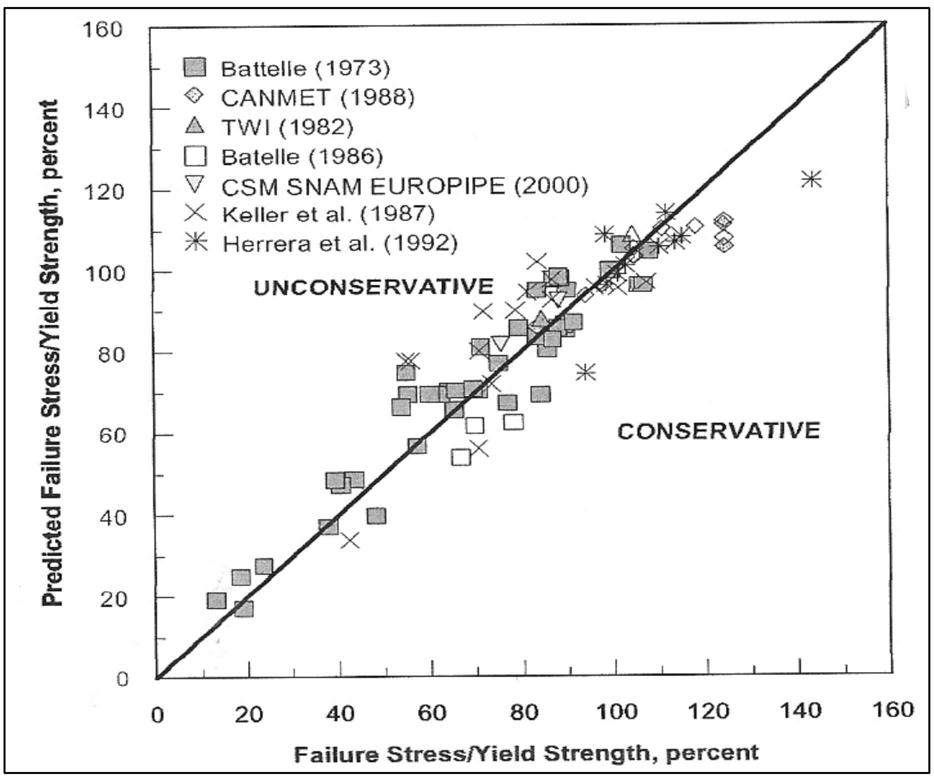


Figure 7.14 – Predictions of the Failure Pressure of Axially Oriented Gouges Using the NG-18 Equation (Cosham and Hopkins, 2002)

7.2.8 Burst Pressure of Combined Dents and Gouges

A dent containing a gouge is clearly a more complex and severe form of damage. Cosham and Hopkins (2002) reviewed in-depth the results of approximately 240 tests on dent and gouge combinations, and the resulting equations describing behavior. Once again, they found that results were difficult to interpret because the simulated dent and gouge damage had been introduced in greatly differing ways in the different test programs.

Cosham and Hopkins reported that two of the most widely quoted models for predicting the burst pressure of dent and gouge combinations are the Q-factor developed by Battelle for PRCI, and the Dent Fracture Model developed by British Gas and adopted by EPRG. The researchers, who present details of the equations (Cosham and Hopkins, 2002; Cosham and Hopkins, 2003), compared the performance of the models with the results from more than 50 full-scale tests (those for which all the necessary test details were available) and demonstrated that the Dent Fracture Model (Figure 7.15) better accounted for the data than did the Q-factor model (Figure 7.16), although both models yielded considerable scatter.

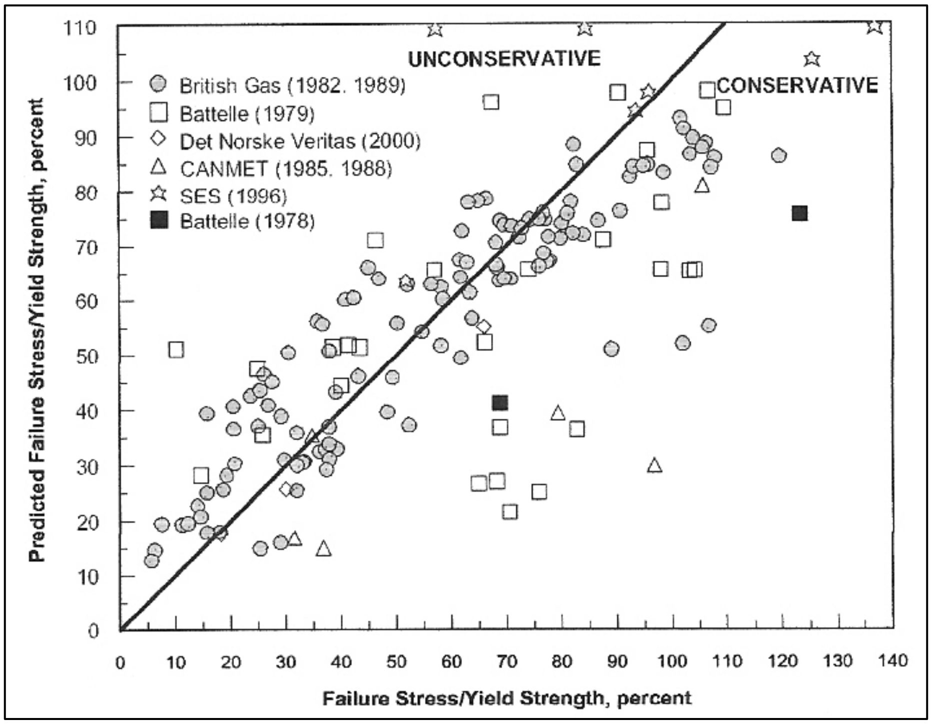


Figure 7.15 – Failure Behavior of Combined Dent and Gouge Damage Predicted Using the Dent Fracture Model (Cosham and Hopkins, 2002)

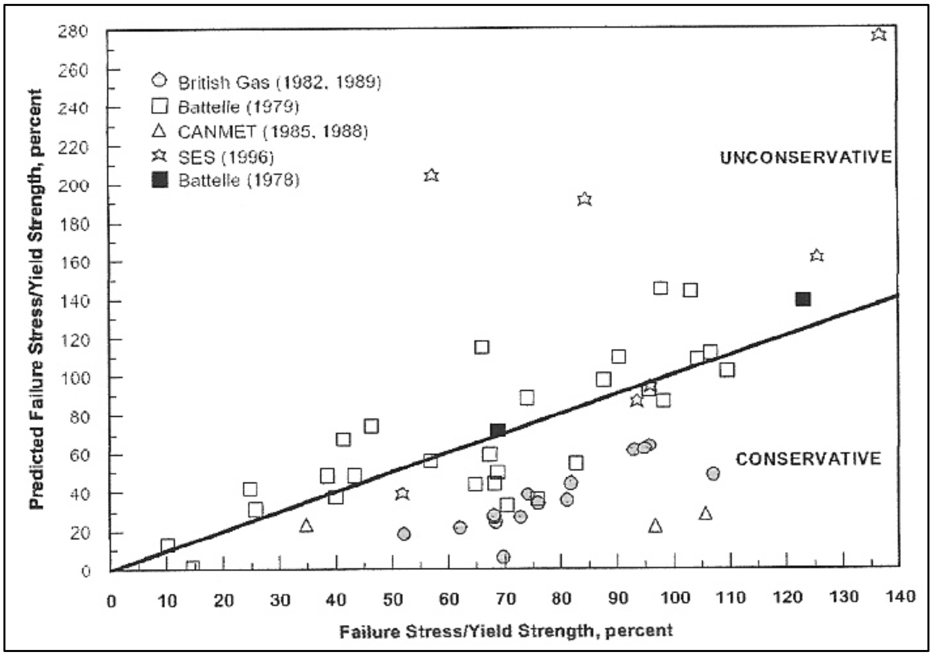


Figure 7.16 – Failure Behavior of Combined Dent and Gouge Damage Predicted Using the Q-Factor Model (Cosham and Hopkins, 2002)

Advantica has recently undertaken an investigation (Francis, Jandhu, Andrews, Miles, and Chauhan, 2005) for the UK Onshore Pipeline Operators Association (UKOPA) to try to broaden the applicability of the Dent Fracture Model. They included factors to accommodate the presence of micro-cracking, residual stresses, and stress concentration at the root of the gouge, and also incorporated a new limit state function to describe the deformation and plastic collapse of the remaining ligament. Figure 7.17 shows how the fracture parameter (Kr) and the collapse parameter (Lr) combine to determine the new limit state function, which is compared with the burst test results. While the scatter is reduced compared to the original Dent Fracture Model (Figure 15), it is still substantial.

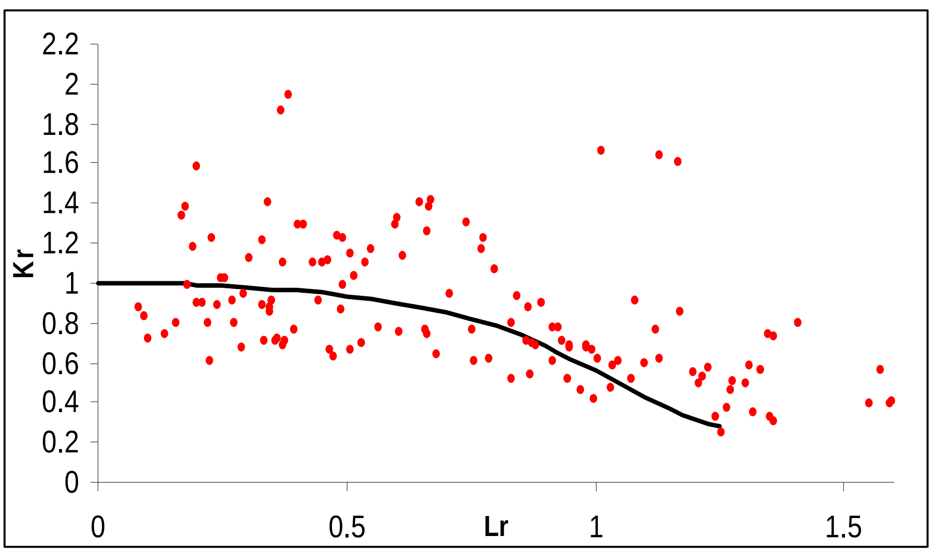


Figure 7.17 – Comparison of the Dent Fracture Model Incorporating the New Limit State Function, with Full Scale Combined Dent and Gouge Damage Test Results (Francis et al., 2005)

7.2.9 Fatigue Behavior and Delayed Failure of Combined Dents and Gouges

Combinations of dents and gouges also reduce fatigue life compared to dents or gouges alone. Leis and Hopkins (2003) report the results of tests undertaken by several organizations and reviewed by Cosham and Hopkins. Comparison of the results from full-scale tests with the model developed by British Gas for EPRG shows that the scatter is substantial (Figure 7.18). Leis and Hopkins comment that the degree of scatter calls into question the viability of the underlying model, though its validity appears to be comparable to that of the other models developed to date.

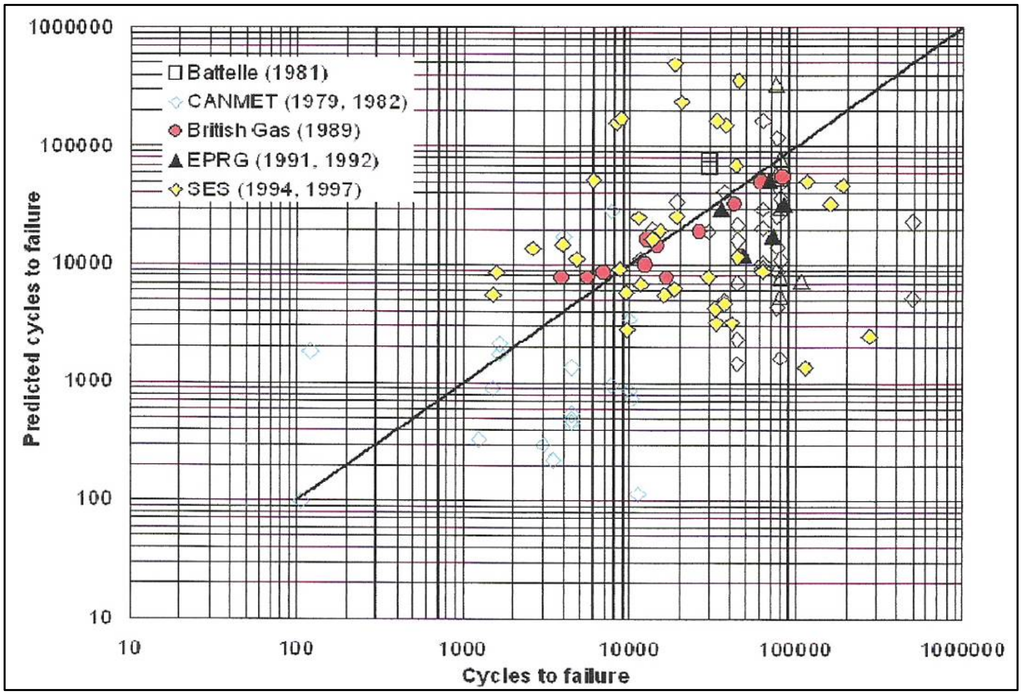


Figure 7.18 – Comparison of Full-Scale Fatigue Test Results on Combined Dents and Gouges, with the British Gas Model (Leis and Hopkins, 2003)

Leis and Francini (1999) have developed a fracture mechanics model to address the delayed failure of dents and gouges from a combination of stable crack growth, creep, and low-cycle fatigue. The model assumes that a crack has been formed at the root of the dent/gouge and grows into the previously-strained material, driven by the combined static and cyclic loading, until failure of the remaining ligament occurs. The feasibility of the model has been demonstrated and its sensitivity to pipe material properties (particularly the reduction of toughness due to prior strain) has been explored. Studies for PRCI (Swankie, Martin, and Andrews, 2005; Martin and Andrews, 2006) have further examined the model, focusing particularly on the influence of prior strain on creep and low cycle fatigue behavior. However, at present, while the model continues to show promise, it has not yet demonstrated the ability to generate accurate predictions of full-scale test behavior.

7.3 Application of the Models – Industry Guidance and Recommendations

7.3.1 Types of Approach

Several of the studies described above have been used as the basis for developing industry guidance and recommendations for the evaluation and mitigation of damage found on in-service pipelines. The evolution of “basic,” “intermediate,” and “advanced” level models for describing and predicting the behavior of damaged pipe was described in Section 7.1.2. This evolution has now reached the stage where three levels of analysis can be identified, as determined by the level of analytical complexity and the amount of supporting information necessary for the assessment:

- Level 1: Acceptance/rejection criteria linked to characterization of the damage and a simple severity parameter, such as damage depth
- Level 2: Screening assessments that rank damage severity – for example, those based on estimated strains calculated from local radii of curvature and those incorporating geometric (D, t, 2c), material (SMYS, UTS) and/or operational (pressure, load cycling duty) parameters.
- Level 3: Fitness-for-purpose engineering critical assessments using specified or actual material properties, finite element modeling, and fracture mechanics to predict the burst pressure and/or remaining life of the damaged pipe.

The Level 1 and Level 2 methods are usually based on conservative (lower range) estimates from sets of test data and service experience, and generally incorporate an appropriate safety factor that accounts for uncertainties in the data and analysis. The Level 3 methods are applied on a case-by-case basis in accordance with the principles of engineering critical analysis and incorporate factors of safety/uncertainty at each analytical stage.

7.3.2 Level 1 Methods (Depth Only)

The work reviewed by Rosenfeld, Pepper, and Leewis (2002) and that undertaken by Fowler, Alexander, Kovach, and Connell (1994) forms the basis for many of the recommendations and the guidance adopted by ASME B31.8 (ASME, 2003) and API 1156 (1997). The guidance is based on allowable dent depth, or an estimated dent strain that takes into account the dent profile and wall thickness. As noted earlier, plain dents or dents with metal-loss corrosion are characterized by a six percent depth or strain safety threshold below which they are not considered to be at risk of bursting or delayed failure, providing that the pipeline does not experience unusually severe pressure cycling. The depth threshold for dents on girth or seam welds is two percent, but may be increased to four percent of the estimated strain if the integrity of the weld is not compromised. The depth threshold for dents that have undergone grind repairs (to remove shallow gouges and/or surface cracking), is four percent.

The Canadian Standard CZ662 (2003) states that "the following dents are considered to be defects that impact pipeline integrity unless determined by an engineering assessment to be acceptable:

- Dents that contain stress concentrators (gouges, grooves, arc burns, or cracks)
- Dents that are located on the pipe body and exceed a depth of 6 mm in pipe 101.6 mm OD or smaller or six percent of the outside diameter in pipe larger than 101.6 mm OD
- Dents that are located on a mill or field weld and exceed a depth of 6 mm in pipe 323.9 mm OD or smaller or two percent of the outside diameter in pipe larger than 323.9 mm OD
- Dents that contain corroded areas with a depth greater than 40 percent of the nominal wall thickness of the pipe
- Dents that contain corroded areas having a depth greater than 10 percent, up to and including 40 percent, of the nominal wall thickness of the pipe and a depth and length that exceeds the maximum allowable longitudinal extent determined in accordance with ASME B31G."

EPRG (Bood et al., 1999) has developed a series of rule-of-thumb methods for determining the burst and fatigue failure of various types of damage. EPRG concludes that plain, smooth dents up to seven percent depth (measured in the pressurized pipe) will not fail at pressures up to 72 percent of SMYS. The guidance is applicable to pipes with 168-914 mm (6 to 7.5 inches) diameter and 5.6-12.7 mm (.22 to .50 inches) wall thickness.

7.3.3 Level 2 Methods

Recent editions of ASME B31.8 contain guidelines on assessing strain fields around dents (see Section 7.2.3 above). Acceptance is established by comparing an estimated strain with a suitable strain criterion. ASME has adopted six percent as the acceptance criterion for plain dents, and four percent for dents at welds. Other expressions may be developed for estimating strains based on more exact theoretical analysis or numerical analysis. The approach allows a more meaningful estimation of dent severity than dent depth alone. The calculation of strain is critically dependent upon the accuracy of the measurements of local radius of curvature. Although there are no specific guidelines, the method should be limited in application to smooth denting where the local radius is several times greater than the wall thickness. Also, the method should not be applied if there are geometric discontinuities or signs of metal removal.

To determine the burst pressure of dents and gouges, individually or in combination, EPRG (Bood et al., 1999) has developed a best-correlation model that equates the failure pressure to a function that includes material strength and toughness, pipe geometry, dent depth, and gouge depth. To overcome the complexity of the model, a series of rule-of-thumb diagrammatic methods has been developed linking defect depth, wall thickness, and operating pressure (e.g., Figure 7.19). The guidance is applicable to pipes with 168-1050 mm diameter (6 to 40 inches) and 5.6-16.2 mm (.22 to .64 inches) wall thickness, with a minimum of 11 Joules (2/3 Charpy) or 8.1 foot pounds toughness.

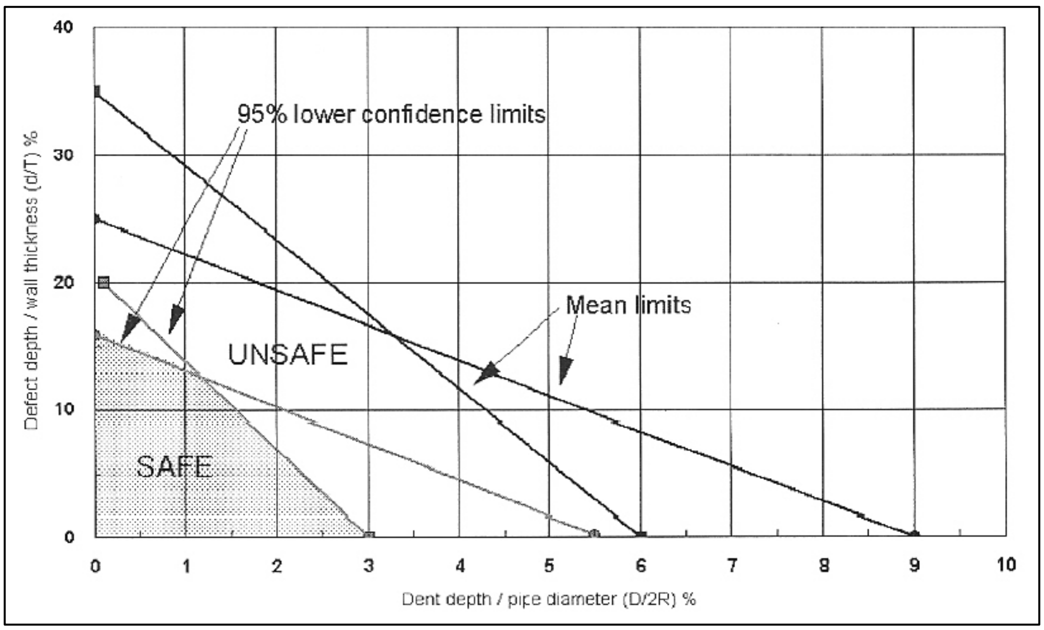


Figure 7.19 – Illustration of the Simplified Representation of Safe Limits for Combined Dents and Gouges (Bood et al., 1999)

To evaluate the fatigue life of dents, gouges, and combinations of dents and gouges, EPRG (Bood et. al, 1999) has developed a best-correlation model that equates fatigue life to a function that includes material strength, pipe geometry, dent depth, gouge depth, and dent/gouge profile. EPRG has also developed a set of guidelines linked to DIN 2413, Part 3 (1993), that incorporates an additional factor of safety (Figure 7.20), to simplify application of the equation. The approach is applicable to dents and gouges up to 10 percent deep in pipe with 168-1220 mm (6 to 48 inches) diameter and 3-18.6 mm (.11 to .73 inches) wall thickness.

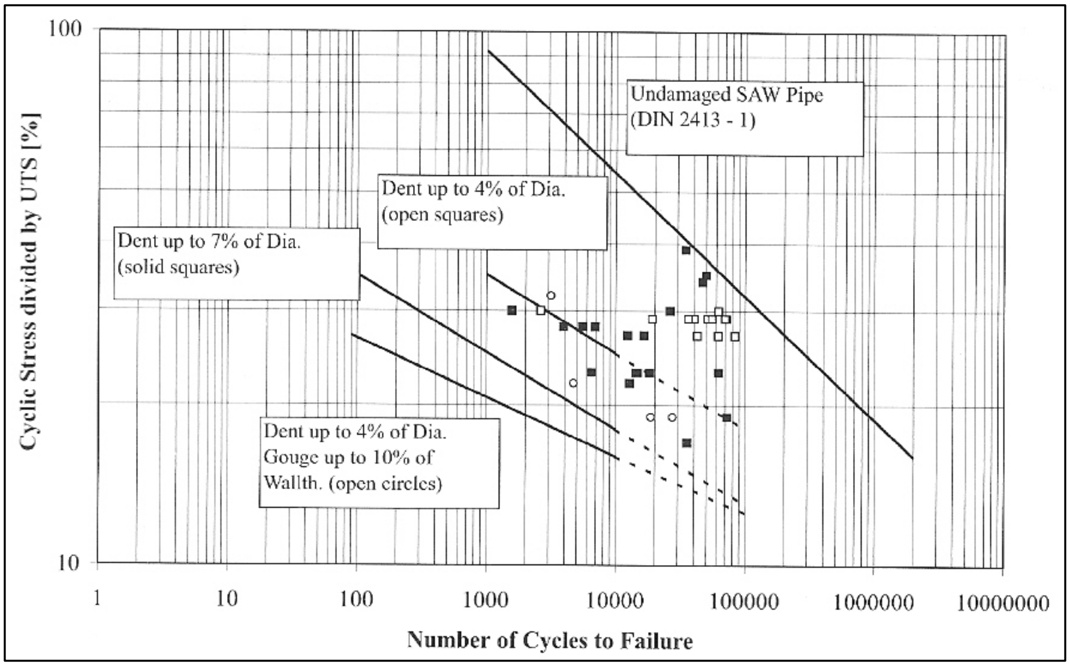


Figure 7.20 – Fatigue Limits for Dents and Combined Dents and Gouges, Related to DIN 2413-1, Including an Adjustment Factor of Ten on Life (Bood et al.,1999)

In the *Pipeline Defect Assessment Manual*, Cosham and Hopkins (2002, 2003, and 2004) have compared the various ASME, API, and EPRG recommendations and selected what they consider to be the best Level 1 and Level 2 methods for assessing pipe burst behavior. To evaluate plain dents (Level 1), they recommend following the simple empirical thresholds proposed by Rosenfeld et al. (2002), Fowler, Alexander, Kovach, and Connell (1994), and EPRG (Bood et al.), although they allow a higher depth threshold – 10 percent – irrespective of whether the depth is measured at operating pressure or at zero pressure. However, they conclude that there are no reliable methods for predicting the burst strength of dents at welds or at kinks. To investigate axially oriented gouges, they recommend applying the NG-18 part-wall flow-stress-dependent equation (with the approximate two-term Folias correction factor and a flow stress equal to the average of the yield strength and the tensile strength), provided that the pipe toughness is at least 21 Joules (2/3 Charpy) or 15.5 foot pounds and the wall thickness is less than 21.7 mm (.85 inches). To assess combined dents and gouges, they recommend using the Dent Fracture Model modified with an appropriate correction factor that accounts for model uncertainty. (Cosham and Hopkins, 2002)

The *Pipeline Defect Assessment Manual* also contains recommendations for assessing the fatigue life of dents and gouges (Cosham and Hopkins, 2004). Cosham and Hopkins recommend use of the original EPRG plain dent fatigue model, modified to correct for uncertainty, to evaluate plain dents. While they suggest use of the most applicable EPRG dent-gouge fatigue models to evaluate combined dents and gouges, they acknowledge that the results demonstrate considerable scatter, and that a substantial correction factor must be applied to account for uncertainty.

7.3.4 Level 3 Methods

Engineering critical analyses or fitness-for-purpose assessments are explicitly included in the Canadian Standard CZ662 (Canadian Standards Association, 2003) as an alternative to Level 1 or Level 2 assessment methods. Other standards and guidance are less explicit, but in several instances they recommend seeking expert advice if such an approach is contemplated.

Engineering critical analysis of mechanical damage usually includes as much detail as is available concerning the geometry of the pipe, the character and geometry of the damage, the relevant material properties (specified or actual), and pipeline operating conditions. The analysis likely will also be based on the most recent versions of the Level 2 methods, customized if necessary to suit the specific situation.

There are no formal standards for conducting an engineering critical analysis. Regulatory authorities require the operator to demonstrate that a satisfactory analysis has been undertaken in accordance with the prevailing best engineering practice.

7.3.5 Summary of Guidance

The basic methods identified in current North American Standards and European Industry Guidance Documents are summarized in Table 7.1 (Batte, 2006). These are predominantly Level 1 assessment methods, although in some instances a Level 2 assessment, such as strain as an alternative to dent depth, is included. The acceptance criteria for plain dents are very similar, although not identical. There are several differences for dents with secondary features; for example, some organizations set acceptance criteria for dents associated with welds and corrosion, whereas others default, directing the operator to seek expert advice. API 579 also addresses assessment procedures for pressurized components with geometric irregularities.

Table 7.1 Summary of Guidance and Standards for Acceptance of Mechanical Damage (From Batte, 2006)

	Plain Dents	Dents at Welds	Dents with Cracks or Gouges	Dents with Corrosion
ASME B31.8	Up to 6% OD or 6% strain	Up to 2% OD or 4% strain for ductile welds. No safe limit for brittle welds	No safe limit	Up to 6% OD for dent and metal loss, as per corrosion criterion
API 1156	Unconstrained: up to 6%OD. >2% requires a fatigue assessment Constrained: no limit provided rock remains in place	Up to 2% OD	Not allowed	Not considered
EPRG	Up to 7% at a hoop stress of 72%	Not allowed	Not allowed	Not allowed
PDAM	Up to 10% of pipe diameter	Not allowed	Assess as a dent and defect combination	Assess as a dent and defect combination
CZ662	Up to 6 mm for <102 mm OD Up to 6% for >102 mm	Up to 6 mm for < 323 mm OD Up to 2% for >323 mm OD	Not allowed	Not allowed if corrosion exceeds 10-40% deep, (depends on axial length)

The methods recommended in the *Pipeline Defect Assessment Manual* are summarized in Table 7.2. These are predominantly Level 2 and Level 3 approaches. It should be noted that the recommendations are based on the state of knowledge at the time of writing, and that the development of new and improved methods is being actively researched by PRCI, EPRG, and others. Additionally, some of the methods are presented as best-fit descriptions of behavior and do not include built-in factors of safety. Consequently, the reader is advised to seek advice before undertaking a Level 2 or Level 3 analysis in order to ensure use of the most up-to-date information.

Table 7.2 Recommended Methods in the *Pipeline Defect Assessment Manual* for Assessing the Burst Strength and Remaining Life of Axially Oriented Mechanical Damage Defects (Based on Cosham and Hopkins, 2003)

	Internal Pressure (Static)	Internal Pressure (Cyclic)
Gouges	NG-18 equations	No method
Plain Dents	Depth less than 10% of pipe diameter	EPRG model
Kinked Dents	No method	No method
Smooth Dents on Welds	No method	No method
Smooth Dents and Gouges	Dent-gouge fracture model	No method
Smooth Dents and Other Types of Defect	Dent-gouge fracture model	No method

7.3.6 Use of the Guidance for Field Assessments

Many pipeline operators have been utilizing the ASME, API, CSA Z662, EPRG, and PDAM guidance to address the threat of mechanical damage. Some have many years of experience (Ironside and Carroll, 2002; McCoy and Ironside, 2004; Warman, Johnston, Mackenzie, Rapp, and Travers, 2006) in applying direct and indirect techniques to assess the severity of mechanical damage and to make repair decisions. The scope and complexity of the decision processes varies significantly among operators.

7.3.6.1 In-Line Inspection Assessments

A first level assessment of mechanical damage is often made using ILI data. Here, dent depth and the presence (or absence) of secondary features (e.g., metal loss) dictate whether the reported damage requires immediate investigation, can be scheduled for evaluation and remediation, can be monitored, or is not a threat to integrity. Operators typically make conservative assumptions when making investigate/don't investigate decisions. Most operators consider damage such as a rock dent to be benign, based on repeat inspections that reconfirm damage characteristics and stability.

While many operators confirm the usefulness of ILI data in identifying and characterizing pipeline damage, most are not confident about the reliability and accuracy of the data when used as the basis for making mitigation decisions. As experience is gained, and as ILI and other assessment methods improve, this situation seems likely to change.

7.3.6.2 In-the-Ditch Assessments

It is much more common for operators to base mechanical damage mitigation decisions on field measurements. For example, Figure 7.21 shows an assessment flow chart for mechanical damage discovered by excavation (Warman et al., 2006). The decision points and courses of action are determined in accordance with ASME guidance and are designed to comply with the requirements of 49 CFR Part 192.

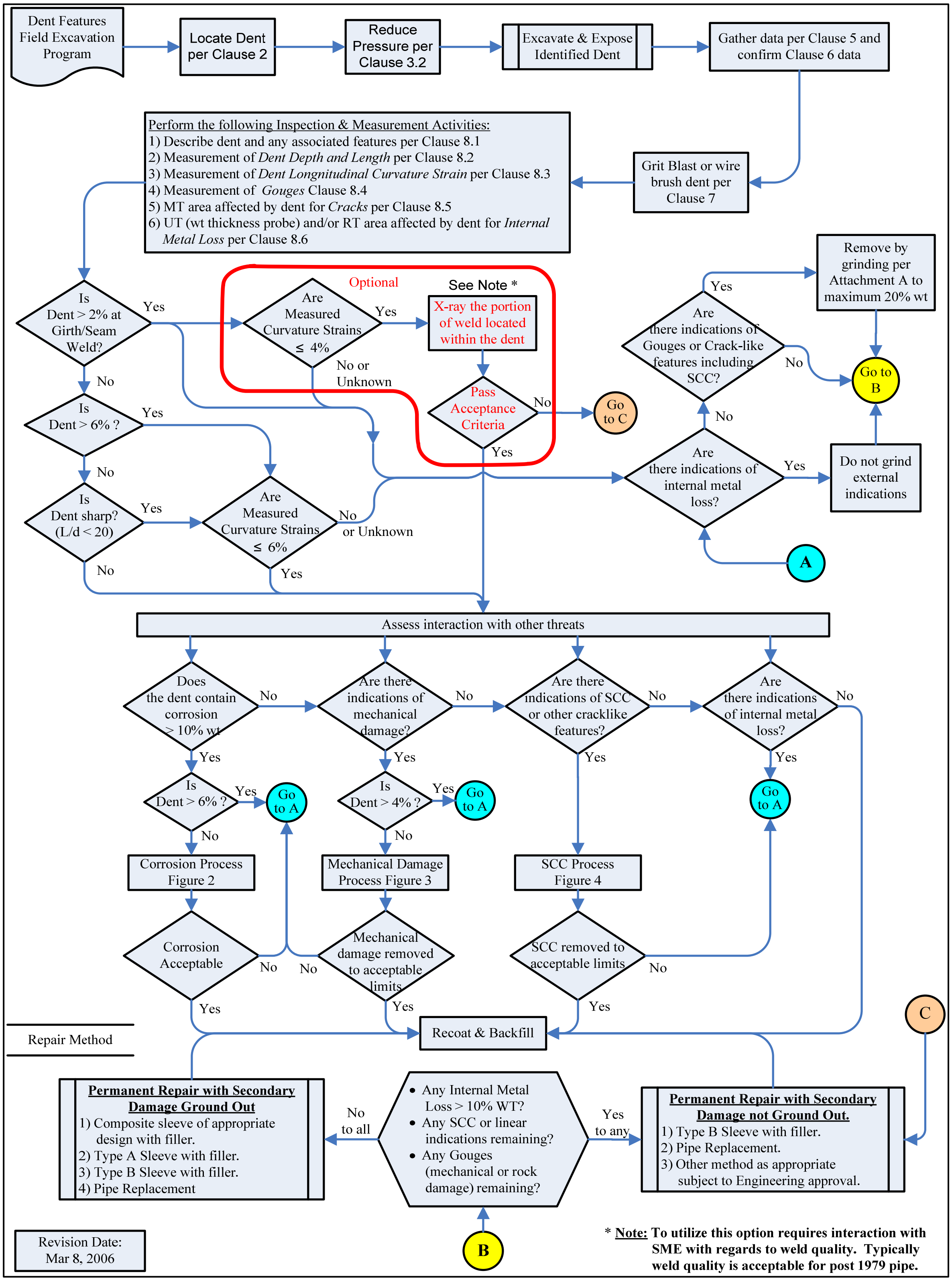


Figure 7.21 – Example of a Flow Chart for Assessing Damage Discovered Following Excavation (Warman et al., 2006)

(2003). Here, the types and extent of measurements and inspections depend on the damage itself. For example, if calculated dent strains exceed a threshold value, cracks and other damage are considered. This type of decision tree considers the factors that contribute to the severity of mechanical damage and how over the life cycle of a pipeline, the damage could affect pipe integrity.

Once in the ditch, most operators (in the United States) will elect some method of mitigation for defects exceeding allowed descriptions based on the justification that, once the damage is excavated, the added cost for the repair is relatively minor in comparison to the cost of the excavation, and regulatory concurrence is generally assured.

7.4 Summary

Mechanical damage can be simple or remarkably complex, depending on the manner in which the damage was introduced, the pipeline's operating history, and numerous other factors. Assessment is especially difficult because there are great uncertainties associated with the factors that determine severity.

The potentially complex nature of mechanical damage and the uncertainties surrounding the variables that determine its severity can make assessment very difficult. In fact, methods to assess mechanical damage can never be as simple or straightforward as those for assessing corrosion. In some cases, no amount of analysis can demonstrate that damage is acceptable simply because factors such as changes in pipe material properties produced by the damage cannot be measured. These factors must be considered in determining the means to manage as well as whether or not to investigate or repair an anomaly.

Assessment methods range from crude but effective to complex, difficult, and time consuming. Any one assessment methodology is not inherently better or worse than another. Instead, the effectiveness of an assessment methodology depends on how it is applied. Simple methods can be effectively used as long as operators recognize their limitations.

A number of observations and conclusions on the assessment of mechanical damage can be made based on the findings from the literature reviews conducted for this chapter:

- Despite the numerous experiments performed to analyze mechanical damage and the substantial quantity of data gathered over the last 50 years, there are still gaps in scientific knowledge in the burst and fatigue performance of damaged pipe. Gaps exist because of the broad range of ways in which mechanical damage can occur and also because of the manner in which experimental damage has been simulated (particularly combined dent and gouge damage) and introduced (with and without internal pressure or external constraint). For example, there are major differences in the manner of test loading – pipe ring tests lack the axial tensile and bending components associated with finite-length defects in the field. In addition, in many tests, supporting data for variables such as material properties, or the presence and size of secondary defects were not recorded and cannot be used to develop improved models.

- Dent re-rounding behavior is consistently described by empirical equations and finite element analyses of deformation behavior. Unconstrained dents generally re-round under operating pressure to depths less than five percent of the pipe diameter on pipes whose operating pressure is approximately 72 percent of SMYS. Re-rounding depends on pipe geometry (D, t) and dent shape; long dents are more likely to re-round than are short dents, particularly in the central region.

- Dent depth is a useful, simple criterion for ranking and screening the severity of damage in plain smooth dents, whether constrained or unconstrained. The depth thresholds of six percent to 10 percent offer simple guidance for many practical engineering purposes. However, more discriminating guidelines that account for dent profile are necessary when the damage is acute or kinked. For example, it has been noted that some pipelines with dents whose depth exceeds 10 percent have continued to operate without failure or other incident, whereas other pipelines with dents whose depth measures only three percent have failed.

- Estimation of dent strain is a useful means of incorporating dent profile and wall thickness in the evaluation of pipe mechanical damage. Resolution and measurement errors affect the results and should be considered in any evaluation.

- Characterizing dents by strain may enable discrimination among those at low or high risk for microstructural damage that could include cracking. Strain estimation methods do not account for the damaging effects resulting from successive tensile and compressive strains associated with the denting and re-rounding process. Strain estimations do not specifically address susceptibility to degradation or crack growth over time on in-service pipelines.

- The reduced depth and strain thresholds of two percent to four percent have proven to be effective engineering guidance for the evaluation of dents with secondary features, such as corrosion or welds. However, the thresholds are based on limited experimental results that often demonstrate a large degree of scatter.

- For axially oriented gouges, there is a strong correlation between measured burst pressures and those predicted using fracture-mechanics-based equations. However, the relationship is more complex for gouges not axially oriented.

- The fracture-mechanics-based equations formulated to describe the burst behavior of combined dents and gouges yield results that exhibit a high degree of scatter. Therefore, the analysis must incorporate a significant factor of safety to compensate for "model uncertainty."

- Similarly, results generated by stress-life equations developed to describe the fatigue behavior of dents, gouges, and combined dents and gouges demonstrate a substantial degree of scatter when compared to the experimental results. Once again, the calculations must incorporate a significant factor of safety to accommodate model uncertainty.

- Models developed to evaluate failure and fatigue life have been demonstrated to provide useful information on the sensitivity of failure pressure and fatigue life to variables such as dent shape and size, pipe geometry, secondary feature shape/location, and material property changes in the damaged region. The performance of these models has not been further validated by comparison of their results against a body of actual experimental data. Nonetheless, the models offer useful guidance and are effectively used by pipeline operators around the world to evaluate and address the threat of mechanical damage.

Current industry guidance in North America and Europe is principally based on Level 1 methods – acceptance/rejection criteria linked to characterization of the damage and a simple severity parameter such as damage depth.

Level 2 assessment methods have been developed to screen damage severity. Examples include the use of estimated strains calculated from local radii of curvature and rule-of-thumb equations that incorporate pipe/damage geometry, material properties, and/or operational loading parameters. The successful application of these methods demands more in-depth analytical knowledge than is required for implementation of Level 1 methodology, including an awareness of contingencies and limitations.

Some guidance documents support the application of Level 3 evaluations, which utilize engineering critical assessment incorporating finite element modeling and fracture mechanics to predict the burst pressure and/or remaining life of damaged pipe. Level 3 evaluations require detailed information on the damage itself, as well as a deep understanding of the mechanisms that drive failure in mechanical damage.

7.5 References

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8 Mitigation

8.1 Definition

Mitigation refers to the actions taken by the pipeline operator upon receiving information that mechanical damage may be or is present at a specific location on its pipeline. The operator must ensure that the measures taken will return the pipeline to a condition comparable to that of the pipeline's entry into service, or to a level permitted by applicable codes. Mitigation actions discussed in this chapter include actions taken in response to reported damage, examination in the field, and suitable repairs. The selection of methods to mitigate mechanical damage depends on the nature and extent of the damage, as well as regulatory requirements, company policies, and cost.

8.2 Initial Response

The initial response to mechanical damage is to establish that the pipeline is currently operating under safe conditions. The initial response is the same, regardless of whether the damage was identified by in-line inspection (ILI), detected by another party, or discovered in the ditch.

Some operators in the United States assume it is not possible to predict a safe operating pressure at mechanical damage or to ensure that the pipeline is safe at its current pressure. When mechanical damage has been identified, these operators reduce the pressure in the pipeline at the location of the damage, commonly to not more than 80 percent of the pipe's recent high-pressure level or the pressure at the time the damage occurred. A pressure reduction of 20 percent provides a factor of safety of 1.25.

In other cases, the operators base their initial response on the perceived severity of the damage. These operators may, for example, reduce pressure at possible third-party damage but not for routine rock dents. Another common approach is to reduce pressure for high stress lines but not for low stress lines. If the hoop stress is below 30 percent of the Specified Minimum Yield Strength (SMYS) for gas pipelines, or below 40 percent of SMYS for liquid pipelines, a pressure reduction might be discretionary because the mode of failure is more likely a leak than a rupture.

Still other operators do not routinely reduce pressure but may place a high priority on quickly investigating anomalies to determine their severity. Also, not all pipelines can be operated with a 20 percent pressure reduction because the reduction would introduce slack zones in the line. Pressure reductions may not be used when the lines transport a product that undergoes a change in phase below a certain pressure. In these cases, a smaller reduction in pipe pressure within the bounds of what is practical may be used.

When a pipe's operating pressure has been reduced, it is generally considered essential that operating personnel understand that the system must not be restored to normal high operating pressure levels and that pressure surges are not permitted until pipe repairs have been completed. (Rosenfeld, 2002)

8.3 Repairs

Typically, the most expensive part of the mitigation process is excavating and exposing the pipeline. Once access to the pipe has been achieved, the incremental additional cost of treating or repairing even major mechanical damage is often considered negligible.

Defects in pipelines may be repaired by a variety of methods. When selecting a repair method, it is important to consider whether the defect growth mechanism (if any) can be prevented, and if not, then the implications for the long-term integrity of the repair should be evaluated. Parameters such as pipe diameter, wall thickness, pipeline maximum allowable operating pressure, grade (i.e., strength level), pipe chemistry, and seam weld type play important roles in assessing the mechanical strength of the pipe. The operator should also consider the inherent risk involved in performing a repair.

Many operators do not consider it safe to enter the pipe ditch in order to examine and repair pipe damage until the operating pressure has been reduced. The importance of reducing operating pressure prior to performing a repair is emphasized by an accident in 1999 in which a gas pipeline failed while personnel were in the ditch examining the reported damage. Fortunately, such incidents have been rare.

Repairs for mechanical damage are generally limited to the following choices, alone or in combination:

- Recoating
- Grinding out of a scrape or gouge to create a smooth contour (with limitations)
- Steel reinforcement sleeve repair
- Steel pressure-containing sleeve repair
- Composite wrap repair (with limitations)
- Hot tap (with limitations)
- Pipe replacement

A repair can be considered temporary or permanent. A temporary repair is one that is to be removed within a period typically specified by the pipeline operator's written procedures. Temporary repairs are sometimes implemented in order to maintain continuous service and are used when the operator plans to return later to complete a more comprehensive repair, such as a pipe replacement. Any repair that is intended to restore the pipeline to service for a period greater than five years, without a requirement for re-evaluation, should be considered permanent. (Jaske, Hart, and Bruce, 2006; AEA, 2001)

Guidance for repair selection may be found in the Pipeline Research Council International (PRCI, now Pipeline Research Council, Inc. [PRC]) Pipeline Repair Manual and in applicable industry consensus standards such as ASME B31.4 or B31.8. Company repair standards are be observed.

All repairs carry limitations or added requirements. These are briefly discussed below. (Jaske, Hart, and Bruce, 2006; B31.4, B31.8; Rosenfeld, 2002)

8.3.1 Grinding

Grinding is a common repair method for some types of mechanical damage. By removing the damaged material in the scratch, scrape, or gouge, and grinding the defect to a smooth contour, the damage is converted to plain metal loss, similar to corrosion. Industry-accepted standard analysis methodologies are then used to predict a safe operating pressure. If the metal removal is within certain specified limits (e.g., the amount and distribution of removed metal does not significantly reduce the pressure-carrying capacity of the pipeline, as specified in applicable standards), then no additional repair other than to recoat the pipe may be required.

Grinding repairs are nearly always accompanied by some form of nondestructive inspection to ensure no cracks are present. Common methods are magnetic particle inspection (MPI) and dye penetrant testing although dye penetrant is not for cracks that are smeared closed or peened over). Some operators grind deeper than needed to fully remove cracks to ensure any damaged microstructure is also removed.

Operators often take extra caution when grinding damage in pre-1970 ERW pipe or other welded pipes where the weld may be of uncertain quality and toughness. Special precautions can include reducing the pipe pressure to a very low level and conducting a thorough nondestructive examination to confirm that grinding the weld area is a safe option. (Jaske, Hart, and Bruce, 2006; B31.4, B31.8; API 5L, 2007; CSA Z662, 2003; Rosenfeld, 2002)

8.3.1.1 Regulations and Guidelines

Repair of mechanical damage by grinding has historically been allowed by several accepted standards:

- The pipe manufacture standard API 5L permits grinding to remove imperfections not coincident with dents to a minimum remaining wall thickness permitted by the pipe product tolerances, between eight percent and 12.5 percent of the pipe wall, depending on pipe size, type, and grade;

- The Canadian pipeline standard CSA Z662 permitted grinding in accordance with a criterion similar to the one subsequently validated by Kiefner and Alexander (1999), though its origin was not documented; CSA Z662 allows grinding as a repair in §6.1.3 & 10.8.5.2, although it also states in §10.8.5.2.3 that:

    - External metal loss resulting from grinding shall be permissible regardless of the length, provided that the maximum depth of such areas is 10% or less of the nominal wall thickness of the pipe.

    - External metal loss resulting from grinding to a maximum depth of 40% of the nominal wall thickness of the pipe shall be permitted, provided that:

        - The longitudinal length of the ground area does not exceed the maximum allowable longitudinal extent determined in accordance with ASME B31 G; or

        - The MOP is less than or equal to the failure pressure of the pipe containing the ground area multiplied by the terms in the following expression:

            MOP <Pfail x (FxLxJxT)
            where:
            Pfail = failure pressure for the pipe containing the ground area determined in accordance with Clause 10.8.5.2.4
            F = design factor (see Clause .4.3.3.2)
            L = location factor (see Clause 4.3.3.3)
            J = joint factor (see Clause 4.3.3.4)
            T = temperature factor (see Clause 4.3.3.5)

- ASME B31.8 (2007) has historically permitted repair by grinding for new pipe to a depth of 10 percent of the pipe wall and currently allows grinding of dents with gouges in in-service pipelines according to the same criteria as repeated in CSA Z662**;**

- ASME B31.4 permits repair by grinding of imperfections not coincident with indentations so long as the resulting metal loss meets the limitations of corrosion-induced metal loss allowed by ASME B31G.

These regulations and guidelines are similar. For example, the allowed length of metal loss removed by grinding is computed as L=1.12B (Dta)1/2 , where parameter "B" is shown in Figure 8.1. (Corder and Burn, 1983) It is apparent that more than one value for B has been recognized as effective. The key point to note is that they are reasonably consistent and similar, with the exception of API 5L, which is actually the most conservative. In the event that the damage cannot be successfully removed within the limits provided for above, another repair method should be considered and applied, as appropriate.

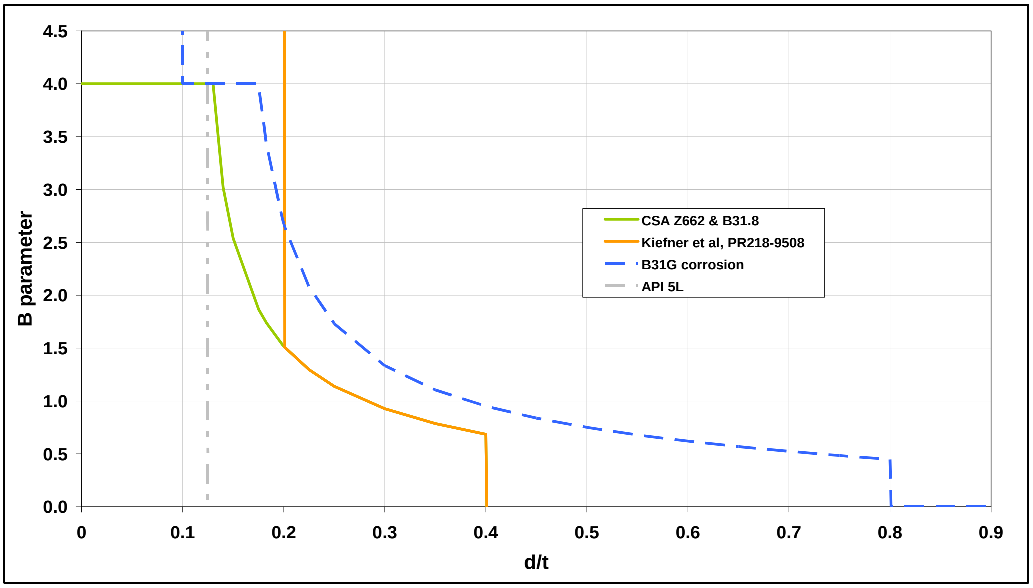


Figure 8.1 – Comparisons of Grind Criteria (Kiefner and Alexander,1999)

8.3.1.2 Test Programs

Physical testing sponsored by PRCI demonstrated the effectiveness of removing damage by grinding. The objective of the research was to demonstrate that:

- Grinding essentially converts mechanical damage to plain metal loss that supports a greater failure pressure than the original mechanical damage;
- The failure pressure after treatment could be reliably predicted by a B31G-like criterion;
- Limits to the safe application of the technique could be determined; and
- Grinding constitutes a suitable technique for repairing mechanical damage within the pipe wall. (Kiefner & Alexander, 1999)

These key points were demonstrated throughout the series of tests performed on pipe of various diameters, wall dimensions, and grades. The tests included a range of damage severity in terms of indentation depth, gouge depth, gouge length, and pressure condition. The tests were performed on pipe pairs where identical examples of damage were introduced in separate pieces of the same type of pipe. For each pair, one sample was treated by grinding to convert the damage to metal loss while the other was left in the damaged state. The two specimens were then pressure tested to failure, or subjected to pressure cycles until they failed by fatigue.

The tests demonstrated that converting the mechanical damage to plain metal loss by grinding the damage to a smooth contour until all cracks were removed improved the overall integrity of the pipe compared to leaving the damage untreated. In many instances, the residual strength improved to a level well above the yield strength of the pipe, even where the damage was severe enough to result in a failure at normal operating stress levels if it had been left untreated. The only exceptions occurred where the indentation was particularly deep or too much metal had been removed. The pressure cycle fatigue life improved by factors of between two and 10. (Kiefner & Alexander, 1999)

The results of these tests were summarized in Figure 8.2 and Figure 8.3. Figure 8.2 shows the improvement in burst pressure achieved through treating the damage by grinding it out (represented by the blue symbols), as compared to leaving the damage untreated (represented by the red symbols). Instances where the dents were too deep or too much metal was removed during grinding (represented by black symbols), such that it was not possible to raise the remaining strength to very high levels, are also presented. Figure 8.3 shows the improvement in pressure cycle fatigue life achieved by grinding out the damage compared to leaving the damage untreated.

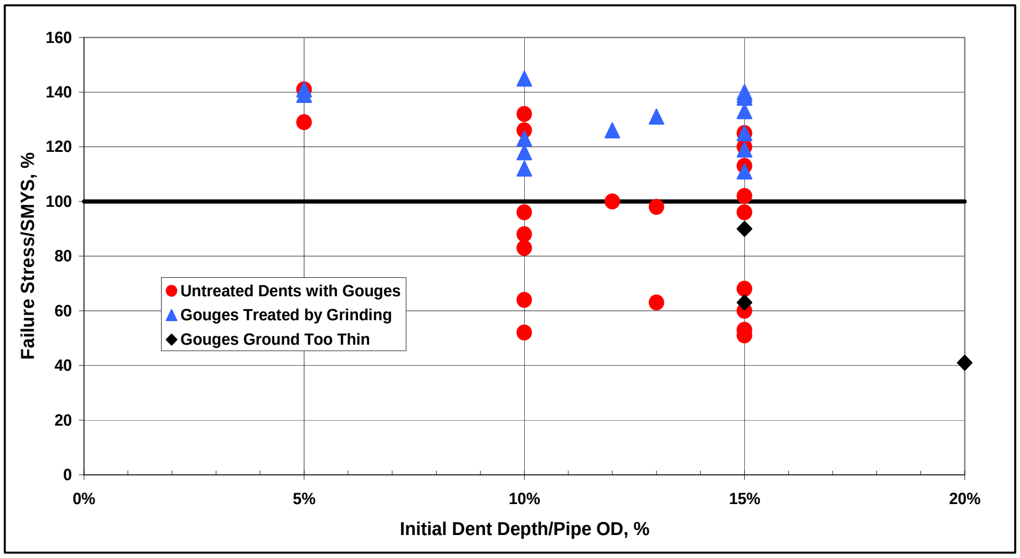


Figure 8.2 – Effectiveness of Grinding for Restoring Failure Stress (Kiefner and Alexander, 1999)

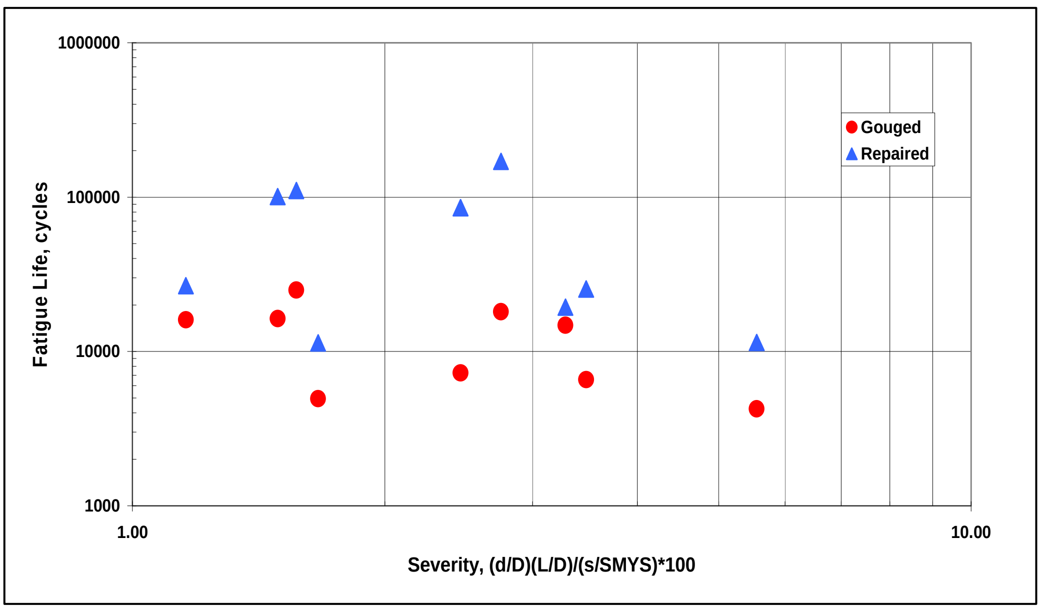


Figure 8.3 – Effectiveness of Grinding in Improving Fatigue Resistance (Kiefner, 1999)

8.3.2 Type A (Reinforcing) Sleeves

Full encirclement steel sleeves include all encircling appurtenance repairs except nonmetallic composite wrap repairs. A steel reinforcement sleeve, also called a "Type A" sleeve, restores the strength of the pipe but is not intended to contain pressure or a leak. The sleeves are not welded directly onto the pipe.

Reinforcement sleeves function by restraining bulging of the pipe at a metal-loss or crack-like defect and by restraining re-rounding of any indentation. Thus, the effectiveness of the sleeve depends on achieving a tight fit-up and requires the use of a hardenable filler to immobilize any radial movement of the damaged area or defect.

Figure 8.4 illustrates the weld configurations of a Type A sleeve. To ensure that adequate restraint is provided to prevent a rupture, the sleeve should be positioned on the undamaged, full-thickness pipe so that it extends at least two inches (50 mm) beyond the ends of the defect. Some operators do not use a backing strip to avoid the risk of the sleeve's longitudinal seam weld attaching to or weakening the parent pipe.

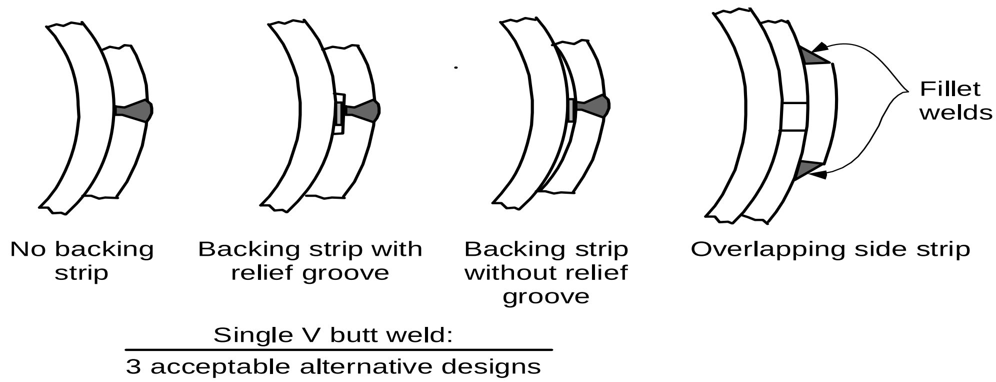
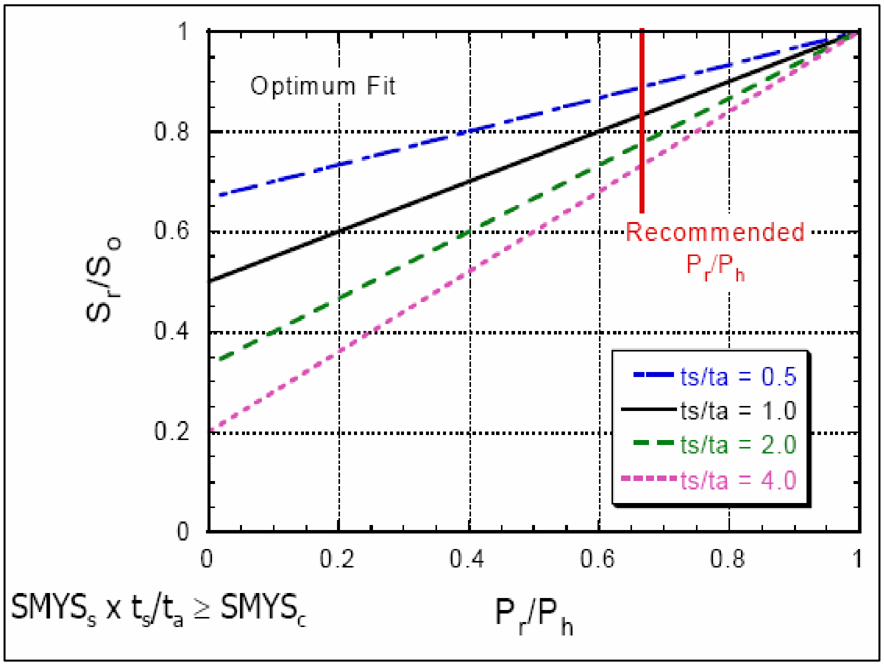


Figure 8.4 – Weld Details for Type A Sleeve (Jaske, 2006)

The ASME Code requires the use of a hardenable filler material when a "Type A" sleeve is used to repair mechanical damage. Two-part polyester epoxy materials are typically used as filler. The filler is troweled into the metal loss or indentation associated with the mechanical damage. It may then be sanded flush after setting. Alternately, the sleeve halves may be installed over the uncured filler, which will mechanically flow into any gaps.

Reinforcing sleeves usually do not share much of the hoop stress that is acting on the pipe without special application techniques. Even if the sleeve fits perfectly and has 100 percent-efficient side seams, it will at most carry one-half of the hoop stress recovered after a pressure reduction if its wall thickness is the same as that of the carrier pipe. The optimum amounts of stress sharing produced by a snugly fitting sleeve for various amounts of pressure reduction are illustrated in Figure 8.5. Since the main function of reinforcement sleeves is to prevent radial bulging at the defect, it is unnecessary for the sleeve to carry much hoop stress. Despite this, a properly installed sleeve can restore the burst strength of a defective piece of pipe to at least 100 percent of SMYS.



t_a	=	actual wall thickness of carrier pipe
t_s	=	wall thickness of steel sleeve
S_o	=	initial hoop stress in carrier pipe
S_r	=	reduced hoop stress in carrier pipe after installation of steel sleeve
P_r	=	reduced pressure at time sleeve is applied
P_h	=	highest pressure previously experienced by the carrier pipe after defect was present
$SMYS_c$	=	specified minimum yield strength of carrier pipe.
$SMYS_S$	=	specified minimum yield strength of sleeve

Figure 8.5 – Theoretical Relationships between Carrier Pipe Stress, Repair Pressure, and Wall Thickness. (Jaske, 2006)

Taking the following steps during installation increases the effectiveness of the reinforcement:

- Reducing pressure in the carrier pipe during sleeve installation. (maximum effectiveness @ 0 psi)
- Externally loading the sleeve to force it to fit tightly against the carrier pipe.
- Applying a formable and hardenable material to any gaps in the annular space between the sleeve and the carrier pipe.

8.3.3 Type B (Pressure-Containing) Sleeves

The pressure-containing repair sleeve, also known as the "Type B" sleeve, is similar to the Type A sleeve, except that its ends are welded to the pipeline. If the sleeve-end welds are made while the pipeline is in service, maintenance-welding procedures are necessary.

All Type B sleeves should be designed to safely operate at the maximum design pressure of the carrier pipe. It is acceptable to use a sleeve that is thicker or thinner and is of lesser or greater yield strength than the carrier pipe within limits as long as the pressure-carrying capacity of the sleeve is at least equal to that of the pipe. Many operators simply match the wall thickness and grade of the sleeve to the pipe material. An installation of a Type B sleeve is shown in Figure 8.6.

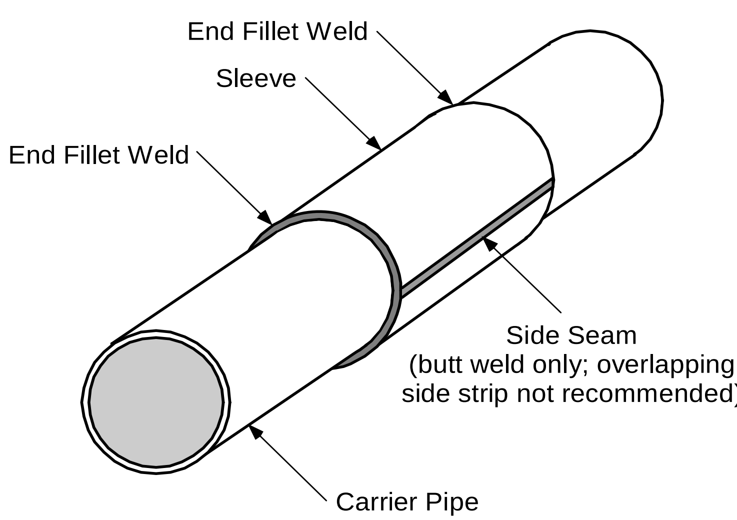


Figure 8.6 – Type B (Pressure Containing) Sleeve Illustration

Implementation of Type B sleeves requires (1) the development of adequate and appropriate welding procedures and (2) the training and qualification of personnel specifically for the purpose of fabricating such sleeves. The objectives of the procedures, training, and qualification should be to ensure full-penetration side-seam butt welds and crack-free end fillet welds. Low-hydrogen consumables should be employed, and the recommended practices outlined in Appendix B of API STD 1104 (2001) or another recognized industry standard should be followed.

Type B sleeves are more sensitive to fit-up than are Type A sleeves and more difficult to apply when the pipe is ovalized or the damage “bulges.” Poor fit-up could lead to misalignment or improper filling of the side seams, which in turn could degrade their reliability. Excessive gaps between the sleeve and pipe at the sleeve ends require additional weld metal to tie the two at the fillet weld root, which introduces greater localized stresses in the weld and could affect its reliability.

As with a Type A sleeve, a Type B sleeve should be positioned so that it extends some distance beyond both ends of the defect. Weight that is added to the pipeline by a repair should be considered in the pipeline operator’s plan for supporting the pipe during and after the repair. (Jaske, Hart, and Bruce, 2006; Rhea, 1995; GE, 2007)

8.3.4 Epoxy-Filled Sleeve Repairs

An epoxy sleeve repair (ESR) system developed by British Gas has been used extensively for permanent repairs on non-leaking pipelines carrying various products. Installation can be performed without losing product, and it does not require shutdown. However, according to the vendor, GE Oil & Gas/PII Pipeline Solutions, ESR application is much more common in Europe than in North America even though extensive testing has been performed on ESR static and fatigue behaviors, and its effectiveness has been thoroughly evaluated and proven by the testing, numerical studies, and system applications. The epoxy repair method can provide permanent repairs to a wide range of damage, including cracking, corrosion, gouges, and gouged dents.

The repair is comprised of two oversized steel half-shells with a standoff distance of several millimeters from the pipe. Bolts are used to center the shells. The side seams are joined by welding or by a bolted flange that encircles the damaged area, leaving an annular gap. The gap is sealed at each end of the sleeve using fast-setting filler. After the seals have hardened, epoxy is injected into the annular space, at very low pressure, until it discharges from an overflow hole on top of the sleeve.

Once the epoxy filler has hardened, the radial bulging tendency is controlled through restraint of the pipe wall, in the same manner as achieved through use of a conventional Type A sleeve. Bonding between the epoxy and the sleeve and the epoxy and the pipe permits the transfer of longitudinal stress and is claimed to also provide circumferential support.

Welding to the pipeline is not required, so ESR can be performed without interrupting product flow. ESR can be used to repair all types of non-leaking defects. In most cases, the repaired area is stronger than the adjacent “good” pipe.

Experience with shells installed over 16 years applied to a variety of pipeline defects has indicated repairs continue to perform satisfactorily. Long-term degradation of the epoxy bonding was investigated and no significant corrosion of the encircled pipe or shell was observed. No long-term degradation of the epoxy bonding has been was investigated, indicating no significant long-term degradation within the temperature range 37 to 122 °F (3 to 50 °C). The ESR is not normally exposed to damaging environments, and is not expected to deteriorate from this cause. General use of similar epoxy products has been successfully established for more than 25 years in other areas such as grouting for the civil engineering industry. (GE, 2007)

8.3.5 Mechanical Clamps

Several types of mechanical clamps are available from various commercial vendors. Figure 8.7 shows a photograph of a typical bolt-on clamp. These clamps are designed to contain full pipeline pressure, so they are generally rather thick and heavy because of the large bolts used to provide the required clamping force. (Kiefer and Alexander, 1999) The clamps normally have elastomeric seals to contain the pressure if the pipeline is leaking at the defect. They can be either installed like a Type A sleeve or can be fillet welded to the pipe like a Type B sleeve to contain a leak in case the seals fail (most clamps fall into the latter category). Operators who intend to weld such clamps to the pipeline should consider all of the implications of welding on a live pipeline. (Jaske, Hart, and Bruce, 2006)

There are also split, bolt-on sleeves for subsea permanent pipeline repairs; these could potentially be used to repair onshore pipelines. Some of these sleeves are designed with circumferential clamping mechanisms at each end so that axial loads are transferred through the sleeve rather than the carrier pipe. This feature can be useful for repairing severe damage, such as a circumferential crack in a girth weld.

Figure 8.7 – Typical Mechanical Bolt-On Clamp (courtesy of T. D. Williamson, Inc.).

8.3.6 Composite Repair System

Nonmetallic composite materials have been used to repair pipeline damage (mainly corrosion), for almost 20 years. Composite sleeves are intended to repair and reinforce non-leaking sections of pipe wall weakened by defects. Composite repairs for pipeline defects work by sharing the hoop load in the pipe wall so that the maximum allowable operating pressure (MAOP) can be safely maintained.

Nonmetallic composite sleeves are proprietary manufactured products. The majority of the composite sleeves consist of glass fiber-reinforced epoxy resins, although carbon fiber-reinforced composite products have recently been introduced. All nonmetallic composite repair products currently available are designed to be installed by wrapping around the pipe. They come in two forms: rigid, preformed, unidirectional or woven reinforced; and preimpregnated or impregnated with resin by the user and laid up wet (uncured). As with steel sleeves, the rigid composite materials are limited to use on relatively straight sections of pipe, while the flexible composite materials can be applied to bends, elbows, and tees.

As is the case with the application of any type of repair device, the effectiveness of a composite wrap repair depends on the ability of trained personnel to follow established procedures and strictly observe the limitations on the conditions of installation specified by the manufacturer.

Historically, composite repair systems have not been considered appropriate to mitigate mechanical damage. However, recent studies have demonstrated that composite repair systems can effectively repair mechanical damage provided that any scrape or gouge has been treated by grinding to a smooth contour such that damaged microstructure and cracks have been removed. One such study demonstrated that repair extends the pipeline fatigue life by a factor in the range of eight to 10. In addition, it was demonstrated that if the mechanical damage is first removed by grinding, the factor increases to 21.6 (Alexander & Worth, 2006).

ASME B31.8 (2003) states that nonmetallic composite wrap repairs are not acceptable for the repair of mechanical damage "unless proven through reliable engineering tests and analysis." Some operators could justify the use of nonmetallic composite wraps for the repair of mechanical damage if the manufacturer had performed sufficient tests to demonstrate effectiveness and to define suitable conditions and limits for such use. ASME B31.4 (2006) permits the use of nonmetallic composite wraps for the repair of indentations, scrapes, and gouges if all surface damage is treated by grinding to a smooth contour, the treated area is examined and verified to be free of cracks, and indentations and cavities are filled with hardenable filler under the wrap. These restrictions and allowances are fully consistent with the published results of composite wrap repair performance tests.

8.3.7 Hot Tap

Hot tapping can be used to remove a defect from an in-service pipeline. The operator may first need to reduce pipe pressure prior to inspection and hot tapping repair. The section of material to be removed by the hole-cutting should contain the entire defect. In addition, the hot tap should be properly designed to resist all of the stresses that will be applied to it.

Clamping hot taps have been primarily developed for subsea pipeline applications and have been considered for onshore repair applications as well. They are split, bolt-on sleeves with a branch nozzle on one of the clamp halves. Circumferential clamping mechanisms, located at each end of the sleeve, seal to the carrier pipe and provide full structural integrity through their welding to the carrier pipe. Grouted tees have also been developed for hot tapping to pipelines without the need for welding. Their construction is simpler than that of mechanical clamp fittings, and they can accommodate larger ovality in the carrier pipe than mechanical fittings. Figure 8.8 illustrates a hot tap application.

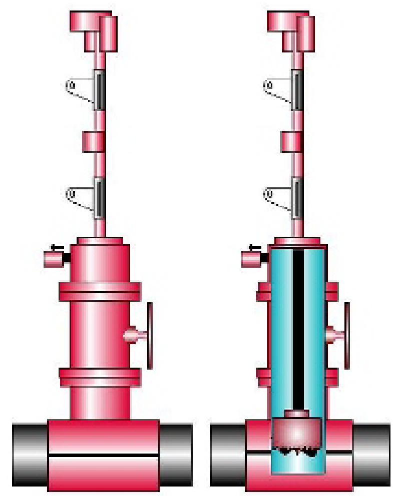


Figure 8.8 – Hot Tap Equipment Connected to Pipe (courtesy: http://www.rafe1914.com)

8.3.8 Replacement of Pipe

In situations where a segment of pipe has sustained extensive damage, it may not be possible to remediate the damage using simple repair clamps or sleeves. In such situations, the available repair solution will involve the replacement of the damaged section of pipe using a suitable isolation technique.

8.4 Summary

This report section highlights the various methods used to repair mechanical damage on pipelines. The discussion focuses on the routine responses necessary to evaluate the condition of a pipeline and ensure its continuous safe operation. Emergency measures, such as those in response to a rupture, leak, or release due to mechanical damage, are not addressed. Furthermore, the study only addresses mitigation measures applicable to onshore pipelines. The pipeline protection and prevention technologies are not covered in this section but earlier in Chapter 5.

8.5 References

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9 Industry Experience

9.1 Introduction

Pipeline operators, as the industry professionals literally "in the trenches" every day, are a primary and very valuable resource for data in the investigation and characterization of mechanical damage.

A total of 10 pipeline operators – representing a diverse cross section of industry professionals in the United States, Canada, and Europe – agreed to be interviewed during the development of this report to gain a better understanding of the significance of the mechanical damage threat to pipeline system integrity, assess common practices for mechanical damage prevention, detection, assessment, and mitigation, and identify discipline areas in which future research may be needed. Each operator was presented with the same series of interrogatories, and their responses were recorded in note form by the interview team, which generally consisted of four individuals, including primary authors of this report. Following the interview, the notes were transcribed and returned to the operator for editing. The report of each operator reflecting any edits was then included in Section 9.2 below. The operator interviews present valid perspectives on mechanical damage. While responses did not drive the content in other sections of this report, insight gained by the authors during the interview was used to enhance the report's content. For example, learning that Operator F uses flowable fill when backfilling as a barrier and means of pipeline identification resulted in the inclusion of the discussion of flowable fills in Section 5.2.4 which discusses backfilling methods.

Operator systems include gas and liquids transmission and gas distribution pipelines. Facilities range from large-diameter transmission pipeline to small-diameter distribution pipeline and encompass steel and plastic pipe. The geographic location of the pipelines varies from remote and rugged terrain, to rural areas, to constrained urban environments. The approximate total system mileage maintained among all operators includes 46,000 miles of gas transmission pipeline (all onshore), 20,000 miles of liquids transmission pipeline (predominantly onshore), and 75,000 miles of gas distribution networks.

Individual operator interviews are presented below.

9.2 Operator Interviews

9.2.1 Operator A

Operator A operates thousands of miles of petroleum product pipeline, principally in the Eastern and Southeastern United States. Its system typically runs at full capacity, so cyclic fatigue threats are generally a relatively low concern. Because most of the system is comprised of large-diameter, thin-walled pipe, mechanical damage is a concern to this operator.

Operator A utilizes a risk-based approach to the prevention of mechanical damage, considering assessments made "in the ditch" to be a form of prevention and examining one-call statistics and locations of construction activity to determine where increases in patrol and survey frequency are needed. To increase the visibility of its pipeline rights of way, the operator mows the pipeline cover area annually. Operator A places a high value on promoting public awareness of pipeline safety and maintains a program of communication with excavation equipment rental companies located within a 50-mile radius of its pipeline. Inexpensive publicity materials such as trinkets, literature, and "811" stickers are given to the rental companies, whose primary customers are homeowners and small commercial businesses who rent excavating equipment by the day or hour. Operator A feels that this public awareness effort, in place for eight months, has been relatively beneficial and plans to trend the data in a few more months to evaluate the program's effectiveness. Operator A stated that experienced operators (primarily other utilities) are the most frequent violators of one-call requirements. In addition, Operator A considers that first-party damage caused by operators or their contractors digging near the pipeline to effect repairs imposes the risk of further damage to the pipeline and imposes a safety risk to personnel. Operator A believes that, at some point, the overall risk caused by the threat of damage or injury is increased by digging to investigate a suspected defect that does not pose a significant threat to pipeline integrity. The operator reports having worked with risk tools to assess overall risk, and is working towards understanding the balance between excavating to investigate threats and the increased risk of a first-party line hit or personnel injury.

Most of the latent damage discovered by Operator A is identified through its aggressive pigging program, which utilizes high caliber in-line inspection (ILI) devices, including high resolution magnetic flux leakage (MFL) tools, geometry tools, wheel-coupled ultrasonic testing (UT), and liquid-coupled UT (compression and sheer wave) tools, and ILI with transverse flux inspection. More than 25,000 miles of its system pipe have been inspected via ILI devices to date. The proactive program of ILI inspection maintained by the operator evolved because of a past history of in-service failures. The operator recognizes that a release from its pipeline carries the potential for serious consequences since a release from approximately 80 percent of the system could impact a high consequence area. Damage is also detected via direct examination, including visual examination, magnetic particle inspection, and ultrasonic inspection. Because of the aggressiveness of its pigging program, more than 30,000 excavations have been conducted. The operator is always searching for damage as a means of managing the integrity threat, no matter what the original purpose of the excavation. Direct examination is employed in each instance and has led to the discovery of mechanical damage and other threats, including stress corrosion cracking (SCC). Of the more than 1,000 digs performed annually by Operator A, more than 60 percent are related to investigation for mechanical damage. However, very few real threats have been discovered.

The operator reports the discovery of significant amounts of rock damage to its thin-walled pipe and finds that double or overlapping dents (i.e., one dent interacting with another) are treated as an integrity issue. The company assesses dents according to the quantitative code criteria, and aggressively excavates dents that fall below criteria. The operator evaluates rock dents and topside dents similarly, according to code criteria, but its response time to these threats differs (i.e., scheduling priority is given to topside dents). The operator uses an appropriate strain-based process to analyze dents with stress risers.

Operator A notes that it has yet to develop confidence in the use of ILI tools for characterizing mechanical damage because too many instances have occurred during its operations in which potentially threatening dents with cracks were uncovered that were not reported by the ILI vendor. Conversely, the company has conducted numerous extensive excavations that have resulted in the discovery of very few integrity-threatening defects. The operator correlates MFL data with field-verified damage data to gain a better understanding of discrepancies. Roughly half of the time, the operator is able to correlate data from damage detected in the field with MFL data that was initially overlooked. Vendors are required to immediately contact the operator if they detect a potential threat, and the operator itself responds immediately to the situation. Data integration remains one of the operator's greatest challenges (i.e., efficiently mapping the data sets derived from two ILIs to one another).

Because of its aggressive implementation of pigging and excavation programs, Operator A feels that "the pendulum has swung" and that many of its problem areas have been addressed. The operator now plans to develop a more strategic approach to the investigation of integrity threats. The operator anticipates encountering fewer defects requiring remediation in 60 or 180 days. Further, the operator expects to realize an increase in the percentage of defects detected that require immediate repair.

Because Operator A's system operates at near capacity, crack-growth damage tends to be a problem only on delivery lines where the flow is less constant (i.e., more cyclical). The operator has uncovered crack-growth damage in existing mechanical damage. In many cases, the crack-growth area is excised and analyzed in the lab. The operator has not experienced any in-service latent damage failures in the past four years, but has detected SCC around dents due to higher localized stresses and strains.

Pressure is not typically reduced before performing an excavation unless the presence of a dent with metal loss, SCC, or gouging is suspected. In these cases, pressure is reduced to 200 pounds per square inch, which the operator admits is an arbitrary reduction level. Pressure reductions are not required for repairs on bottom-side dents. Operator A's program requires detailed, real-time, in-the-ditch characterization of dent information: data are instantly transmitted from the field to the engineering office for analysis. Of the 1,000 excavations it performs each year, the operator estimates installing 400 sleeves to repair damage. Type A sleeves are used predominately. If cracking is suspected, the operator will grind the pipe surface to remove the anomaly and place a Type B (pressure containment) sleeve over the defect. Only a handful of repairs made each year require pipe replacement. Operator A reports having applied for approximately ten waivers for extension of response time.

Needs identified by Operator A to enhance the integrity assessment of its own system include better tools that will enable it to confirm the presence of a threat and need to excavate ("We dig up 100 defects to find one true threat") and the ability to seamlessly integrate operating data with multiple-run ILI data sets – that is, the successful integration of data management systems with integrity management systems. In 2008, Operator A will utilize combination geometry and MFL tools on its system, and anticipates a challenge in integrating the data. Furthermore, Operator A recognizes that the evolution of multiple technology ILI tools warrants advances in analysis and data processing. Operator A's experience with combination technology tools indicates that signals from the various technologies are still processed and assessed independently by the ILI vendor and only assessed in an integrated fashion through manual interpretation. Signal analysis of integrated data sets is recognized by Operator A as an opportunity to enable better characterization of damage from ILI data.

9.2.2 Operator B

Operator B is an interstate natural gas transmission company comprised of multiple subsidiaries and maintains a total of 15,000 miles of pipeline in the United States, including 1,000 miles of offshore pipeline.

The company inspects approximately 1,000 miles of pipe each year; an average of 800 miles are inspected using both caliper and magnetic flux leakage (MFL) survey tools. The caliper tool is applied first to verify pipeline piggability. Operator B anticipates that its use of caliper tools will decline after baseline surveys have been conducted and the ability to utilize an MFL tool has been verified.

The company's operating philosophy is predicated on the concept of prevention; prevention has been a focal point for a long time. In fact, the operator states that its prevention and public awareness efforts predate the development of federal integrity management regulations. Not surprisingly, prevention is likewise the centerpiece of the operator's integrity management plan for mechanical damage. Operator B implements various initiatives to comply with API 1162 requirements for public awareness (including mailings and meetings with excavators and emergency responders) and employs preventative measures such as pipeline surveillance, aerial patrols, and right-of-way maintenance. The operator also performs more patrols within high consequence areas. Operator B's strong belief in promoting public awareness as a preventative measure is further evidenced by its creation of a corporate public awareness manager position. The public awareness manager is responsible for promoting the continuity and consistency of public awareness initiatives across the operator's component firms and ensuring that best practices are followed. Operator B is currently developing a database to track the effectiveness of its prevention efforts, although it has not established specific performance indicators and believes that it is premature to attempt to measure program effectiveness. The operator is also reviewing the overall effectiveness of industry prevention and best-practice initiatives. The operator acknowledges that stronger penalties must be imposed upon violators of one-call laws, up to and including incarceration (as is the case with Occupational Safety and Health Administration violations).

While data integration is a concern, Operator B believes that its data correlation capabilities exceed those of the majority of companies. Operator B manually integrates caliper and MFL data to confirm dent with metal loss features, since the accuracy of the computer-based data integration process is unconfirmed. One of the company's goals for 2008 is the integration of one-call information with in-line inspection (ILI) data.

The operator performs very few excavations each year to evaluate the mechanical damage indications detected via ILI – less than five or six indications are investigated per year, based on caliper tool information. Most defects are bottomside dents, and dents that are shallow (less than six percent) and elongated (feet versus inches). The operator believes that very few instances of mechanical damage occur because its pipelines are located in very remote areas with flat, non-rocky terrain. Of the operator's 15,000 miles of system pipe, less than 1,000 miles traverse populated areas. Although pipe segments located in populated areas were anticipated to sustain a greater number of topside dents, the operator has found that more incidents of damage occur to pipe segments located in remote areas. The remote location incidents are largely caused by farming activity. Data indicates that not only does mechanical damage pose a major integrity threat to the operator's onshore pipeline system, it also poses a significant risk to its offshore pipeline network. The operator feels that the need to extend the discussion of damage prevention, including "one-call" notification to offshore systems, is critical.

If mechanical damage is suspected during routine surveillance, the operator employs a caliper tool or performs its own excavation. If a defect is encountered, or if a defect of unknown characteristics is suspected, pressure is reduced by 20 percent. Once a defect is exposed, pressure may be further reduced. No special precautions are taken for suspected rock dents. As well, no distinction is made among procedures for addressing topside and bottomside dents. The operator considers that it is more important to adequately characterize the dent than to search for the causal factor(s). False positives (ILI indications of defects where none are found to exist upon excavation) are not a concern because of the small number of excavations performed to expose suspected mechanical damage. Operator B is currently rewriting its procedure for characterizing dents that incorporate secondary features and is developing procedures for performing strain calculations on dents with stress risers.

Permanent repair measures include excision of damaged line segments and installation of Type A or Type B sleeves. Composite repair devices are installed to mitigate dents with no secondary features.

Operator B feels that enhancing existing or developing new technology will not solve mechanical damage problems. Instead, the operator believes that increasing public awareness through a sustained communications effort is integral to mitigating the mechanical damage threat.

9.2.3 Operator C

Operator C is one of the largest natural gas transmission pipeline companies in North America. The number of pipeline defects excavated each month (1 to 3) is not considered by the operator to constitute a significant threat. No instances of third-party mechanical damage to the system occurred in 2007, and there has not been a pipe failure from a dent during the company's entire operating history, which the operator attributes to the low population density and adequacy of depth of cover (average cover depth is four feet).

The operator feels that public awareness campaigns promoting the "call before digging" concept have been very successful in preventing third-party damage to the Canadian portion of its system. The company's practices to prevent third-party damage include the use of signs and aerial patrols. In addition, its equipment operators are trained in the proper procedures to follow when performing an excavation close to the pipeline. The operator does not currently participate in any prevention technology research and development efforts.

Rock dents are the primary cause of mechanical damage to the operator's system. Rock shield and sand padding are used to reduce rock damage, but occasionally, instances of rock damage do occur. The company has investigated but is not currently considering the use of coatings that minimize rock damage.

Because corrosion poses a significant threat to the operator's system, corrosion threats dictate the frequency of in-line inspections. The operator utilizes the services of an ILI vendor who compares MFL signals and correlates signal response to dent depth. The operator notes that the determination of dent depth via ILI is not yet a technically acceptable solution in HCA areas in the United States. The operator's response to dent detection is determined by U.S. and Canadian code criteria (the applicable Canadian code is CSA Z662). The operator considers that MFL signals are typically "overcalled" because of pipe rebound (i.e., the tool may indicate a dent depth of six percent, but upon excavation, the dent may actually demonstrate a depth of two percent). However, the operator's experience is that even though MFL tends to overestimate dent severity, in most cases, it does detect some form of anomaly on the pipe. The ILI vendor analyzes the data to determine the size of the defect. If a stress riser is present, the vendor immediately contacts the operator. The vendor typically consults with the operator in cases where the dent data appears to indicate a marginal problem. Strain and metal loss calculations are performed in house. Operator C tends to analyze ILI data before taking action. The operator considers defect discovery to start when the defect analysis is complete, but nonetheless mobilizes its field crews for response upon receipt of the preliminary information from the vendor. Because of early mobilization, obtaining environmental permits for immediate response is not a problem.

All dents that exhibit metal loss are excavated in HCA areas in the United States. Pressure reductions are incident specific and not prescriptive. The operator relies on industry guidance to determine acceptable pressure reductions. The lowest that the company will reduce pressure is 50 percent of the pipeline's maximum operating pressure (MOP) without blowing down the line, but typically, the pressure reduction is 80 percent of MOP.

Operator C's primary method of repair of stress risers in dents is to grind out a defect. Following magnetic particle imaging, and prior to grinding, the operator will perform a metal loss calculation (RSTENG). Operator C uses etching to reveal hard spots that may occur at gauges. Repairs are most frequently made with Type A sleeves. Type B sleeves are used if the defect is an internal crack. Clockspring-type and composite repairs are acceptable, but the operator notes their standard operating practice chooses to require a 40 percent de-rating of system pressure. This operator's decision is arbitrary and is neither general practice nor a regulatory requirement. In addition, the operator does not alter its excavation practices for permafrost or frozen soil conditions, but recognizes that special care must be taken during excavations in muskeg conditions because of the effects of dent rebound. A special analysis is conducted on the pipe in these locations.

Operator C's system contains latent, "aged" dents that would fail acceptable dent depth requirements, but that have met critical risk assessment criteria. Because the operator's system is not generally subject to large pressure cycling, the latent dents are not considered to present an integrity threat.

Additional research on methods to detect mechanical damage other than ILI would be beneficial. In addition, Operator C considers that research is needed to establish reliable criteria for the sizing and repair of dents. Such research would confirm whether the existing dent repair guidelines are too conservative.

The operator believes that industry improvements in dent-sizing tool accuracy can be brought about by generating competition among ILI vendors.

9.2.4 Operator D

Operator D currently operates a total of approximately 5,100 miles of HVL and crude and refined petroleum pipeline in the United States, which includes 3,300 miles of onshore pipeline and 1,800 miles of offshore pipeline. A significant portion of their on-shore pipeline mileage is located in metropolitan areas.

The operator maintains an aggressive mechanical damage prevention program that was recently revised to fully integrate measures prescribed by API 1162 and API 1166. One new initiative under the program is the development of a right-of-way technician position dedicated to monitoring activity in the pipeline right-of-way. The right-of-way technician's primary responsibility is to protect the pipeline from 3rd party excavations. In addition to the creation of this position, the company has developed more performance metrics to evaluate the effectiveness of its damage prevention initiatives. Variables tracked include the number of one-call notifications received, and the number of encroachments that have occurred. This data is important, as it enables the operator to adjust its prevention program based on outcomes from these metrics. The company utilizes a centralized one-call center to receive and screen tickets, allowing the right-of-way technician to focus on field activity. Operator D plans to hire a consultant to evaluate the effectiveness of its public outreach efforts under API 1162. The operator is also very active in the Common Ground Alliance and has integrated the CGA Best Practices into their damage prevention efforts.

The pipeline right-of-way is mowed as needed. Currently, warning signs are placed according to "line of sight" criteria in designated areas based on risk. However, the operator is transitioning to "line of sight" marking as their standard for all of their onshore pipelines. The company also buries a bright orange mesh snow fence with a printed warning (i.e., "Warning: Petroleum Pipeline") in portions of the right-of-way of its new pipelines and when existing pipelines are exposed for maintenance activities. Aerial reconnaissance is an important means of detecting encroachment problems and monitoring pipeline integrity. Aerial patrols are periodically conducted using fixed-wing aircraft, and, in some cases, helicopters, if conditions warrant. Aerial patrols are not conducted in response to one-call notifications. Patrol frequency depends upon the characteristics of the particular pipeline segment and the level of activity within the pipeline right-of-way. Pipeline segments in metropolitan areas are likely to be patrolled more frequently. Patrols of the system are also conducted on foot. Operator D is a strong advocate of right-of-way damage prevention projects and fully supports the PRCI's damage prevention research initiatives. Pipeline system maps and GIS centerlines are revised periodically based on updated data obtained from in-line inspections, excavations, and other activities on the ROW. These on-going updates to maps and centerlines further improve damage prevention efforts by providing higher quality information for use by ROW technicians, air patrol pilots, and one call centers.

The operator receives approximately 100,000 one-call notifications annually. Approximately 10 percent of the notifications require marking of the lines or other field follow-up activities. In 2007, the operator's right-of-way technicians reported that there were 85 instances of encroachment where the violator did not utilize the one-call system. Fortunately, the incidents did not involve any contact with the pipe. There have been only three or four incidents involving contact with the pipe in the last three or four years. The majority of third-party damage to Operator D's system is typically caused by excavation contractors or horizontal directional drillers – industry professionals who should have known better. The operator acknowledges that first and second-party damage has also occurred.

While Operator D believes that pipeline monitoring systems such as the GE Threat Scan may be beneficial, the operator prefers to invest in technology that will help prevent damage, rather than detect damage after it has occurred. The operator currently supports research on aircraft-mounted sensors that will provide a more comprehensive view of the right-of-way by augmenting the visual reconnaissance traditionally performed by air patrol pilots. The "SENTRI-LD" research project, that includes participation from PHMSA and NASA, is an example of research on aircraft-mounted sensors that may ultimately include their use on unmanned aircraft. Excavations are performed by contractors hired by the operator. Historically, ILI using MFL and caliper pigs has been the operator's primary means of detecting mechanical damage. At present, the operator prefers to use combination tools, rather than conducting caliper assessment separately from MFL.

From 2002 to the present, the operator has investigated approximately 500 pipeline features that could potentially be considered to be mechanical damage. Of this total, only a very few features were actually determined to threaten pipeline integrity. However, Operator D does not assume that any dents are "safe" and drives vendors to report dents of any depth. The operator wants to receive all available data.

The operator has found that caliper or other geometry tools can fail to detect small dents and that MFL tools tend to be more effective in this capacity. Ultrasonic tools have also been used by Operator D to detect mechanical damage, although these devices are more often used to detect long seam defects or stress corrosion cracking. The operator does not employ phased-array tools or perform engineering direct assessment to identify mechanical damage. Operator D ensures that its ILIs conform to code requirements and employs the same assessment criteria to evaluate mechanical damage in both high consequence and non-high consequence areas. However, the operator responds more quickly to indications found on pipe in high-consequence zones.

Operator D utilizes an automatic data integration tool. A small dent that normally would not require action would be investigated further if the area is near a known line crossing. Operator D anticipates the future integration of one-call information with ILI data.

Pressure reductions of the operator's system depend on the particular situation. The operator follows the guidance in ASME B31.4 for pressure reductions when responding to ILI defects.

Magnetic particle investigations are also performed when the line is exposed. Suspected cracks are analyzed through non-destructive testing. Linear indications are addressed as dictated by the particular situation. Data on features are collected in a database. The operator uses this information to verify the ILI vendor's ability to identify the feature as well as to determine if the in-field measurement correlates to the ILI data. The operator has also performed comparisons to determine if a previous tool run identified indications found on a subsequent tool run.

Historically, repairs are made immediately following in-the-ditch assessments, regardless of code requirements. The operator's logic was that once the defect had been excavated, it makes sense to proceed with repair. Generally, a more detailed analysis of the defect was not required with this approach. However, more recently, the operator has transitioned to repairing defects in accordance with ASME B31.4 rather than installing a sleeve simply because the defect was excavated. Repairs for mechanical damage are made by applying Type A or Type B sleeves. Type B sleeves would most likely be used to repair linear indications, typically following a review with a metallurgist. Operator D does not perform composite or clockspring for permanent repairs. It also does not commonly use mechanical clamps to repair defects. Cut outs are performed when required. The operator may reduce pipeline pressure to perform repairs.

Operator D believes that one-call enforcement is essential to reduce the likelihood of mechanical damage and that future research is needed on technologies to enable operators to remotely monitor their right-of-way.

9.2.5 Operator E

Operator E maintains 5,000 miles of crude and refined petroleum and product pipeline systems. While the majority of the systems are located in rural areas, the operator notes that some of the worst incidents to its pipeline have occurred in these locations, typically during installation of field or drainage tiles.

Excavation-related mechanical damage is considered to be a significant threat to the operator's system because of its unpredictability.

The operator utilizes four primary methods of prevention:

- Conducting frequent aerial patrols – the pipeline and its right-of-way are inspected by aerial patrol once a week, rather than once every two weeks, as required by code.
- Participating in one-call membership – the company actively supports the one-call system. The operator also uses software that tracks one-call notifications to ensure completeness of response.
- Staking with right-of-way markers – the pipeline right-of-way is clearly marked to alert excavators, contractors, and third parties.
- Monitoring the right-of-way – the operator believes it has been more progressive than other companies in implementing surveillance measures, i.e., American Petroleum Institute (API) RP1166.

The operator fully complies with the public awareness efforts mandated by API 1162, and during 2008-2010 will phase in measures to satisfy API 1166 requirements.

Operator E receives more than 120,000 one-call notifications each year, and estimates that seven percent of these warrant a field visit. Since the company's system traverses several states, response time complies with specific state requirements. However, Operator E often arranges to be on site when an excavation is initiated, to respond to the one-call notification at the same time. This also ensures that the excavator is fully aware of the pipe location and proceeds cautiously. On-site presence at the project's inception also reduces the likelihood that the operator will have to return at a later stage to evaluate pipeline integrity. It is Operator E's policy to be on site during an excavation when the excavation is in proximity to the pipeline.

Operator E fully supports legislation to enforce one-call compliance. Third-party failure to contact the one-call system has figured in a significant percentage of strikes and near misses to the operator's system. For example, the company's records for 2005 and 2006 indicate that notifications were not given through the one-call system in 40 percent of the actual damage and near-miss incidents that occurred on the pipeline. Furthermore, the majority of those incidents involved private contractors. In recent years, the percentage of incidents caused by private contractors has declined to approximately 20 percent. Also, approximately 30 percent of near-misses and damage incidents in 2005 and 2006 were attributed to excavations that were started before the excavator said he would start or before the operator could mark the pipeline, a trend that may be reversed when measures to satisfy the requirements of API 1166 are fully implemented. No instances of first-party damage have occurred on the operator's system over the past few years.

The weekly patrols have proven effective in detecting problems and have alerted the operator to an average of six excavations each year in the pipeline right-of-way. The operator has not yet performed real-time surveillance or utilized impact sensing to monitor for encroachment.

Operator E defines mechanical damage as "deformation with metal loss." If an in-line inspection (ILI) vendor reports such damage, the operator will investigate. If a deformation with no metal loss occurs, the deformation is treated according to code. The operator applies the same criteria to evaluate damage sustained by the pipe in both high consequence and non-high consequence areas, but will remediate pipe damage in high consequence areas first.

High-resolution magnetic flux leakage (MFL) and caliper tools are Operator E's primary method of detecting mechanical damage, although specialized tools are employed, if necessary. The operator inspects an average of 1,000 miles of pipe each year. The baseline ILI performed on the pipeline detected latent mechanical damage. Defects identified in subsequent runs are being cross-referenced to the baseline ILI data.

The operator's reporting threshold required of vendors is stringent. Any anomaly with a depth greater than ¼ of an inch is reported as a plain deformation. Any deformation that demonstrates no metal loss, but has permeated the pipe to a depth of two percent and is located at a girth weld or long weld is examined. Any metal loss defects are also reported and subsequently excavated.

Since 2005, the operator has utilized combination tools – high-resolution MFL and caliper pigs. The operator does not feel confident about the accuracy of dent depths reported through the caliper pig, because the data can be compromised by factors such as overburden or rock beneath the pipeline. The high-resolution MFL combination metal loss/caliper pig is estimated to be 90 percent accurate in detecting and characterizing topside deformations with metal loss in pipe greater than 12 inches in diameter, and 70 percent accurate in assessing bottomside anomalies with metal loss. There is a 50 percent range of detection rate on smaller-diameter pipe.

Latent damage threats to Operator E's system are less likely because of the company's proactive pigging program. There would be a greater threat of an immediate strike to the pipeline.

Operator E employs magnetic particle testing to inspect dents, but seldom detects anything that is worrisome, such as metal loss. Plain dents detected for the 2004-2006 period include 94 topside dents and 65 bottomside dents. Gouges without dents have never been encountered.

All deformations with metal loss are examined as a special category. If a gouge is detected or if there is a question as to whether a dent has metal loss, the operator's ILI vendor will err on the side of caution and presume that metal loss has occurred. In these cases, both types of defects would be reported as metal loss defects.

If a dent is shallow, the operator will buff it out or place a protective sleeve over it. If a pressure reduction is necessary prior to affixing a repair sleeve, the operator would only reduce pressure by 20 percent, at most, unless circumstances dictated otherwise.

If metal loss is suspected on a topside dent, the operator always derates the pipeline by 20 percent. However, pipeline pressure is not reduced for bottomside dents. Pressure is not reduced for plain dent deformations unless the dent depth is greater than six percent, nor is it reduced just because the dent happens to be located near a girth or seam weld. Pressure is also not reduced simply for the removal of rock beneath the pipeline.

The operator's crews are constantly on the alert for signs of mechanical damage, regardless of their primary purpose for performing field work. Operator E speculates their vigilance has resulted in the detection of as many mechanical damage threats as routinely discovered during aerial patrols.

Repair decisions are guided by a flowchart developed for that purpose. No strain calculations are performed in the field; when a dent is detected, the operator proceeds straight to repair. The only types of repair performed are Type A and Type B sleeve repairs, full encirclement, and external clamping. If no cracks are detected, the pipe will be fitted with a Type A sleeve. If cracks are identified, a Type B sleeve is applied. The deformed area is filled with a hardened steel epoxy and the sleeve is then clamped. There have been no fit-up issues with Type B sleeves. Operator E did use special clamp sleeves approximately 15 years ago, but discontinued their use because problems were encountered.

While grinding out a defect is a common means of repairing damage, the operator may still elect to remove the stress riser and apply a sleeve to protect the deformation area. Cutouts are not commonly performed and are most often used to repair leaking pipe, which is a rare occurrence.
Composite repairs are performed to remediate metal loss due to corrosion, but are not performed to mitigate deformations or cracks.

Operator E regards electronic white lining as a promising improvement in damage prevention. Acoustic detection and fiber-optic detection are not considered by the operator to be cost-effective technologies, and are in fact much more expensive than the operator's aerial patrol. The operator hopes that ILI technology will improve, so that it will be possible to more accurately determine in the field whether a deformation must be investigated or not.

In summary, public awareness is considered by Operator E as integral to alleviating the encroachment problem. While participation in the state one-call system is essential and very beneficial, the operator firmly believes that the pipeline industry needs to champion stricter enforcement measures to reduce the incidence of mechanical damage.

9.2.6 Operator F

Operator F operates more than 7,000 miles of refined product and crude oil pipeline in the United States. The operator's system is comprised of pipe ranging from 1920s vintage to recent construction.

The operator regards mechanical damage as one of the leading integrity threats to its system and to the industry. On average, three mechanical damage incidents occur per year on the operator's system that result in a release. While mechanical damage could occur from first and second-party activity, Operator F considers that the largest threat is caused by third parties that fail to notify the one-call system.

Standard measures are employed by the operator to guard against mechanical damage. Elements of Operator F's mechanical damage prevention program include use of the one-call system, aerial patrols, right-of-way monitoring and maintenance, public awareness programs, internal excavation procedures, and participation in CGA and API/AOPL committees. The operator considers the one-call system to be very beneficial. The company conducts aerial patrols of its system every one to two weeks and regards the patrols as essential, particularly in densely populated areas and areas of new housing construction where third-party encroachment is more prevalent. During an aerial patrol, contact is maintained with the pilot to obtain real-time data, as required. The operator also employs field personnel who respond to one-call notifications. These individuals also routinely meet with contractors who plan to excavate near the pipeline, to ensure that they are aware of the pipeline's location and understand the need to proceed cautiously.

Field personnel are utilized to monitor the right-of-way, maintain a visual presence, and verify that the pipeline is marked. The operator utilizes "line of sight" markings, but finds that markers are often removed by third parties, such as homeowners and landowners. Several measures are taken to help prevent the possibility of mechanical damage during construction and excavation activities. A company representative is required to be present whenever a third party excavates the operator's pipeline. The operator also considers backfilling its pipeline with pipeline identifiers and some type of barrier, such as plastic warning tape, orange construction fencing, flowable fill, or even concrete slabs. Rock shield is also used in rocky terrain and is applied circumferentially to maximize pipe protection.

Right-of-way maintenance is prioritized based on the use of the land, the potential impact on high consequence areas surrounding the pipeline, and the condition of the right-of-way. Operator F has used a variety of approaches for marking its pipelines and maintaining the condition of its right-of-way. Typically, the trees along the right-of-way are side-trimmed every six years to increase visibility of the aerial patrol and the ground is mowed every one to three years to increase the visibility of the markers. The operator has considered the use of herbicides in select areas to inhibit growth of the right-of-way, and will conduct a pilot study in 2008 to evaluate its performance in keeping the rights-of-way cleared. Operator F has also considered not clearing the right-of-way either due to wetland restrictions or as another approach to impede third-party access to the pipeline area and reduce mechanical damage incidents. In these areas, the operator has installed tall markers to ensure that the pipeline is sufficiently marked. The operator has not employed technology that permits real-time surveillance and video-recording of the pipeline.

The operator reports that it received more than 350,000 one-call notifications in 2007. Approximately 80,000 calls were sent to the field crews for further investigation and 4,000 calls impacted the pipeline.

Operator F actively supports pipeline safety and public education and awareness programs. The company has recently implemented and trained its employees on several new field procedures designed to mitigate the occurrence of first and second-party damage. Operator F has also been very active in the community, working with emergency responders and local representatives, but notes that while community activities are beneficial, they cannot target all of the individuals who are the primary source of the mechanical damage threat.

While very supportive of the one-call approach, Operator F believes that more stringent one-call laws are urgently needed. Contractors who don't bother to use the one-call system are the primary instigators of incidents that occur on the operator's system. Utility contractors and grading contractors pose a particularly significant problem because they have the tools to penetrate closer to the pipeline. Farmers can cause damage, but pose a lesser risk because the operator meets with them to discuss their activities and the potential impact on the pipeline. Homeowners can also cause damage, but typically do not have the equipment to perform deep excavations.

Operator F is evaluating the success and impact of its prevention practices, but many of the benefits cannot be easily measured. Incidents of mechanical damage are investigated to identify the cause - whether or not there is a product release. The operator also examines the one-call records to determine whether an incident was in fact reported and what its response was to the one-call notification.

Few instances of mechanical damage have been detected by the operator while patrolling the pipeline for leaks. Operator F requires that a field representative be on site each time its pipeline is exposed. If Operator F discovers that the pipeline has been exposed by an excavation and no representative was present, the operator will often perform exploratory excavations in response to right-of-way encroachments.

The majority of mechanical damage on the operator's system is detected through in-line investigation (ILI) utilizing the combination of caliper and high-resolution metal loss tools. Operator F notes that the caliper pig by itself has limited usefulness in detecting mechanical damage, as the tool simply identifies a reduction in the diameter of the pipeline material. The operator also expressed disappointment in the ability of more advanced technologies, such as high resolution metal loss tools, to reliably detect and characterize mechanical damage – line hits, gouges, dents with gouges, etc. While the operator has experienced some success, it has been limited to a few instances. Operator F has found that the majority of mechanical damage is either not reported by the ILI or inaccurately labeled as another type of anomaly. In addition, Operator F has found through field investigations that the vast majority of the "dents with metal loss" reported by metal loss tools have not been mechanical damage or injurious in nature. Still, the operator believes that the use of combination tools, which employ both deformation and metal loss technologies, allows for a more thorough investigation of the pipeline, permits correlation and verification of data (including ILI data w/ construction or material data), and consequently yields a more accurate analysis of pipeline integrity.

Following an ILI investigation, the operator analyzes the data and prioritizes the anomalies that are considered important for further investigation. ILIs are conducted to determine which anomalies must be excavated and examined in the ditch. The operator will excavate and examine dents that are reported with metal loss or the presence of stress risers. However, as noted, ILI has not been particularly reliable in detecting dents with metal loss in the operator's system.

Pressure is reduced during an excavation when the purpose of the excavation is to investigate an immediate repair condition. The excavation crews have the full authority to reduce pressure or completely suspend pipeline operation if they have any concerns.

Mechanical damage data is profiled through non-destructive testing, magnetic particle investigation, and other methods. The operator desires to improve its ability to identify the severity of a dent. If a constrained dent (i.e., rock dent) is excavated, the constraint will be removed and the pipeline repaired to keep the pipe from flexing. If linear indications are detected, the anomaly is immediately repaired. Strain calculations using profile measurements are not routinely performed. Instead, the operator will repair the anomaly. Dents greater than two percent on welds are automatically investigated. The operator does not have a rule for defining double dents. The operator has performed fatigue cycling analysis on all its pipelines that operate at more than 50 percent of SMYS.

Operator F has utilized industry standards and practices to develop its dent repair criteria. All dents that are measured in the field as equal to or greater than two percent are repaired. Depending on the severity of the dent, Operator F will typically utilize composite sleeves, welded-end steel sleeves (Type B), or pipe replacements as repair methods. Operator F rarely utilizes Type A steel sleeve repairs because of corrosion concerns. In addition, system pressure is always reduced to 50 percent of the maximum operating pressure to install a steel sleeve.

Operator F will not allow composite repairs if a dent depth is greater than six percent or the deformation includes a linear indication that can not be removed by grinding. If a gouge is detected, Operator F most often repairs it with a steel sleeve, but also allows grinding up to 40 percent of the wall thickness.

The operator continues to investigate all mechanical damage reported by ILI tools even though it has had limited success. If the operator has conducted several ILIs on the pipeline, data from all runs are compared to determine whether changes have occurred since the initial ILI. Tool tolerance differences among runs cause the most difficulty.

Dents caused by rocks are not inspected differently than those caused by other factors. The operator inspects rock dents for linear indications using non-destructive testing or magnetic particle inspection. Historically, rock dents have not posed a significant problem for the operator's system because much of the system is comprised of smaller diameter pipe operated below 50 percent of SMYS.

The operator tracks all dents and scrutinizes the performance of the various detection tools employed. Data is forwarded to the appropriate ILI vendor for follow-up. Operator F fully investigates every mechanical damage incident to determine the root cause, which includes checking the one-call system to see if notification was provided. All near-misses are tracked as well; in fact, the operator recently updated its system to enhance its tracking capabilities.

Operator F advocates the use of existing industry tools to prevent and detect mechanical damage threats, although the operator acknowledges that no one tool provides comprehensive coverage by itself or yields consistently reliable data. The operator believes that the one-call system is a key component of the overall integrity threat reduction equation, in combination with public awareness initiatives, stricter enforcement of existing laws, and development of new legislation to curb encroachment activity.

9.2.7 Operator G

Operator G is a natural gas distribution pipeline operator whose systems include more than 35,000 miles in the Northeast that were formerly separate operating entities. The company's system pipe composition includes 6,500 miles of cast iron, 12,000 miles of plastic, and 16,500 miles of steel pipeline (6,800 miles of which is unprotected). There are approximately 500 miles of transmission pipeline in the operator's system; approximately half is classified as covered pipelines under the Integrity Management Program rules. The operator considers mechanical damage to present the greatest integrity threat to its system.

Key elements of Operator G's transmission mechanical damage prevention program include weekly patrols of transmission lines in Class 3 and 4 locations. The transmission lines, most of which are located in Class 4 areas, operate at 40 percent of SMYS or less. The Class 4 areas are patrolled by vehicles, while transmission lines in rights-of-way and Class 1 and 2 are patrolled by helicopter. If evidence of excavation is found during patrols, the operator will screen one-call information to determine the extent of activity near its pipeline. Depending on the level of activity (i.e., sprinkler installation versus deep excavation), the operator performs a "mini" direct assessment (DA). In most cases, the operator will perform this mini-DA if activity is detected near its transmission lines. To date there have been 1138 of these "suspect" locations tested, with 187 excavations and 25 damages found and repaired.

Operator G has provided training to local fire departments, in addition to other activities performed in compliance with API 1162, and uses line-of-sight markers on its transmission lines. The operator has only recently implemented enterprise-wide damage prevention process owners that report to its regional officers.

Mechanical damage on the operator's distribution system typically is detected when the pipeline is struck. Occasionally, the operator discovers latent mechanical damage when the pipeline is exposed. Operator G's transmission system is generally unpiggable; only approximately 30 miles of the system can be inspected via ILI. External corrosion direct assessment (ECDA) is used to detect corrosion as well as mechanical damage. The operator estimates that mechanical damage has been identified and found 25 times using ECDA on 1138 suspect locations as noted above. However, typically only damage to the pipe coating is found. Areas of coating holidays are analyzed for further damage. Rock damage is not a significant big issue for the operator, as ground conditions are generally sandy.

On the piggable portions of its system, Operator G utilizes both caliper and MFL tools. The operator has found corrosion at transition zones (where the piping extends above grade) and under the above grade coating. Other defects found include a minor dent and wall loss at a sleeve due to an arc from either an AC current or a lightning strike. When damage is detected, the operator will consider dent depth and will also validate ILI data by correlating it with field measurement data. The operator will also perform a remaining life calculation and will either x-ray the pipe or perform other nondestructive testing. Strain calculations are not performed.

Operator G does not typically reduce system pressure before excavating to investigate transmission pipeline damage, primarily because its transmission pipeline operates at a low SMYS and because the company's field procedures require hand excavating near the pipe to reduce the likelihood of a strike that could cause significant damage.

The few mechanical damage defects Operator G has experienced on its transmission pipeline have been repaired utilizing a variety of methods. The operator does not identify a preferred repair method. Approximately ten composite repairs have been undertaken in the past five-year period, to repair both mechanical damage as well as corrosion. Due to the age of its system, the operator could not recall an instance in which a repair sleeve was applied to remediate a problem, but did recall performing a hot-tap repair to remove a stress concentrator. The operator does not have plastic transmission pipelines. The operator performs cutouts to mitigate damage to plastic distribution pipe. Cutouts are also performed to replace segments of cast iron pipe, as necessitated by pipe composition or if undermined by other construction activities.

In contrast to its low number of transmission pipeline incidents, Operator G reports over 860,000 mark-out tickets and an average of 3.16 damages system per 1,000 tickets for all of 2007, as compared to an average of 3.54 during 2006. The operator reports repairing 558 leaks caused by excavation damage in 2006. Most of the leaks occurred on its distribution pipelines.

With regard to future research, Operator G feels that new technology capable of better pinpointing the location of underground damage would be beneficial in reducing the number of excavations required to investigate mechanical damage threat.

9.2.8 Operator H

Operator H is a European operator who maintains an approximately 7,700- mile (12,500-kilometer) gas pipeline system comprised of 3,700 miles (6,000 kilometers) of high-pressure and 4,000 miles (6,500 kilometers) of low-pressure pipeline predominantly situated in densely populated areas within tight geometric constraints that include proximity to buildings and other structures.

Mechanical damage is the greatest overall threat to the operator's pipeline system, while external corrosion is the primary time-dependent threat. Historically, only a few pipeline failures have occurred on Operator H's system, which the operator attributes to the ruggedness of its system design. The operator notes that the most recent failure caused by mechanical damage occurred two years ago. The damage, a small leak in the pipe, resulted from deep plowing to establish drainage, but the pipe did not rupture.

Key elements of the operator's damage prevention program include participation in an excavation notification and response network similar in nature to the one-call system used in the United States and Canada, patrolling of the pipeline right-of-way aerially (by helicopter, once every two weeks or approximately 25 times per year) and on foot, and implementation of public awareness program initiatives. The operator continuously monitors its right-of-way to prevent encroachment and considers its approach to be effective.

In the operator's country, the government now advocates use of the excavation notification and response network, and the failure of an excavating party to comply is currently without legal consequences except possible liability claims. The operator anticipates that stricter laws will be implemented shortly and notes that such laws are already in effect in northwestern Europe. Operator H estimates that it receives notifications of 18,000 excavations per year; of this total, the operator supervises 6,500 excavations. Aerial surveillance generates 15,000 notifications; of these, 4,000 are followed by further inspection.

The pipeline right-of-way is frequently monitored to detect evidence of and protect against impacts from encroachment. Operator H maintains contracts with the owners of the properties through which the pipeline travels. The contracts include specific provisions that prevent landowners from performing any activity that could negatively impact the pipeline, such as excavating or constructing along the cover area or in the vicinity.

Although approximately 15 strikes occur on the pipeline system each year, approximately five of these cause significant damage. If Operator H detects evidence of excavation, coating surveys may be performed. Coating surveys are conducted as part of direct assessment or in response to data indications from pigging. Overall, pigging is the predominant means by which mechanical damage is detected. The operator estimates that, on the average, approximately 1/3 of the indications from in-line inspection (ILI) that are excavated for verification are caused by mechanical damage; the remainder is caused by corrosion. Pigging is employed to investigate large-diameter pipe. Direct assessment is used to evaluate small-diameter pipe.

Operator H calculates its own risk controls. The right-of-way distance established for a particular pipeline segment depends on the operator's assessment of the level of risk imposed. At a minimum, the operator typically maintains a 16-feet (five-meter) safety zone on either side of the pipeline.

While the right-of-way is marked to facilitate aerial patrol, Operator H does not normally place signs in the ground to alert the public. If the risk controls indicate that additional measures to warn the public are needed, then the operator may employ slabs and markers, but their use is not standard practice.

Operator H's search for mechanical damage is performed in conjunction with its investigation for system corrosion, which is conducted at frequent intervals. The primary means by which Operator H is alerted to mechanical damage on its system are notifications from parties who strike the pipeline and contact the company to report the incident, normal pigging operations, and coating surveys.

Prior to 1999, Operator H performed ILIs on one pipeline once every five years. Since 1999, the operator has conducted more frequent ILIs. Operator H has an inspection program aimed at maintaining integrity in view of corrosion as the determining threat. ILIs are conducted using MFL and geometry combination tools. The operator prefers combination tools for ILI. The decision to excavate is based on the assessment of the (mechanical) damage. Operator H uses assessment methods based on the research results of both PRCI and EPRG (assessment of dents, dent/gouges, and metal loss). Strain calculations are not performed for dents with gouges. The operator observes a two percent dent depth reporting threshold. If an ILI identifies a dent with metal loss, such as a gouge, the operator automatically excavates to investigate the damage. If a smooth dent is detected, calculations are employed to determine whether excavation is necessary.

Generally, rock dent damage does not occur on the operator's system because the terrain of the pipeline corridor is composed predominantly of sand, clay, and peat, with very few rocks.

Operator H believes that the geometry pig is sufficiently reliable for dent detection, but also correlates its MFL and geometry data (combination tool). However, the operator notes that determining the reason for metal loss – that is, whether metal loss is due to corrosion or associated with a gouge – is difficult through ILI. If multiple ILIs are required on a pipeline, the operator employs the same evaluative criteria for each.

Pressure is reduced by 10 percent for all excavations performed. Prior to excavation, the operator considers data relating to pressure cycling and dents and gouges so that a greater pressure reduction can be implemented, if required. Also, on all excavations, manual excavating is required within a one to two-foot (half-meter) radius of the pipe.

If a dent is discovered, the coating is removed to evaluate the dent profile. Magnetic particle investigation is always performed to evaluate the pipe's external surface. Operator H does perform wall thickness measurements to assess pipe internal diameter, but reports that it does not have adequate technology or methods to check for cracking on the inside of the pipe in case of a sharp dent.

ILI data are linked to the pipeline segment data; the welds and other markers are used to determine the position of a particular segment of the pipe. The ILI data and other relevant data of the pipeline (repair) are managed in a Pipeline Integrity Management System.

Repair methods employed by Operator H consist of replacement of the damaged pipe section, and application of pressure-containing, steel-welded sleeves and clockspring devices. All sleeve repairs are designed to ensure pressure containment, since the operator believes that this is the safest approach. Mechanical damage repairs chiefly involve use of steel-welded sleeves. However, Operator H no longer uses epoxy-filled sleeves for pipe repair because of previous experiences in which these exhibited unsatisfactory performance.

Composite repairs involve clockspring application. Clockspring repairs are performed for gouges (but not dent/gouge combinations) if the direction of the gouge is the same as that of the pipe, since the primary pressure on the pipe would be internal. Unlike most companies, Operator H does not reduce pressure beyond 10 percent for clockspring repairs. The dent is filled before applying the clockspring. The dent is assessed according to the likelihood of fatigue as a degradation mechanism.

In evaluating deficiencies in industry knowledge and valuable directions for future research, Operator H notes that damage prevention and damage identification and characterization are particularly important issues. The operator believes that right-of-way monitoring is among the most beneficial measures for mechanical damage prevention. Consequently, the operator takes an interest in studies on the use of satellite imagery for surveillance. Operator H does not actively participate in such studies.

The operator also believes that future research should focus on improving methods to evaluate pipe strain from dents and gouges and developing better tools for analysis of the damage itself (for example, tools that enable more definitive strain analysis calculations in the ditch). Consistent with the sentiments expressed by a number of pipeline companies interviewed for this mechanical damage report, Operator H notes that one of its greatest concerns remains whether or not it must excavate a suspected anomaly, and acknowledges that it would support initiatives that improve the capability of ILI tools to drive the excavate/don't excavate decision.

9.2.9 Operator I

Operator I operates gas transmission, distribution, storage, production and gathering systems in the northeastern United States. The operator's system totals more than 22,000 miles of pipe, which includes approximately 19,000 miles of distribution pipe, and 1,000 miles of transmission pipe. The distribution system is comprised of both steel (approximately 14,000 miles) and plastic (approximately 5,000 miles) pipe. The focus of the interview with this operator was on its distribution system.

In general, mechanical damage poses a lesser threat to the operator's system than other integrity threats. However, Operator I reports that its pipe does incur numerous strikes; many of these occur without the company's immediate knowledge. Mechanical damage is a much more significant problem on the company's distribution pipelines, but the potential for large-scale damage resulting from failures on its distribution pipelines is less than damage to its transmission lines.

The operator has developed and implements a multifaceted mechanical damage prevention program. The company actively participates in the one-call notification system. Because of its desire to view the one-call tickets that are called in, the operator maintains its own one-call ticket screening system. In addition, a damage database is maintained to track incidents of mechanical damage. The damage database alerts the company to incidents that involve repeat offenders; if the operator determines the repeat offender is causing damage due to unsafe excavating practices, the operator personally contacts the offender to discuss safe practices.

Public awareness initiatives are a key component of the damage prevention program. The operator fully complies with API RP 1162. Meetings are held with emergency responders, including local fire chiefs, as well as with school board representatives and others. Operator I also participates in three separate damage prevention councils which are comprised of representatives from contractors, utility companies, and other pipeline companies who meet regularly to discuss mechanical damage issues. The operator regularly places advertisements in newspapers that emphasize the importance of "sight, sound, and smell" in detecting damage caused to pipelines. Direct mail is another medium by which Operator I reaches out to the public. Flyers are included in mailings to various audiences to remind recipients to call before excavating.

Line markers are the only media used to visually identify the pipeline. Buried yellow warning tape is installed at time of pipeline construction to alert excavators to the presence of main and service lines. If tracer wire has not been installed along plastic pipeline, or if the tracer wire is broken, marker balls are on occasion employed. These devices, approximately five inches in diameter, emit a signal that enables locators to confirm the presence of the gas pipeline.

Right-of-way maintenance is yet another important component of the operator's damage prevention initiatives. The pipeline right-of-way is mowed annually. The operator notes that it is in the process of developing a centralized database to track right-of-way mowing and clearing. The company desires to modify its scheduling so that it can mow the right-of-way before leak surveys are conducted.

Finally, the operator employs fixed wing aerial patrols to scrutinize its transmission lines. These patrols incorporate high-resolution video technology. A third party reviews the video and informs the operator about the type of right-of-way cleanup needed. The reports enable the operator to compare results from one reconnaissance to the next. Real-time monitoring of the system is not performed at present. If a right-of-way incursion is observed at the time of an aerial patrol, the pilot will make immediate notification to operator.

Third-party excavators are the most likely group to strike the operator's system, while second-party excavators are infrequently involved in strikes.

Operator I reports that it receives approximately 300,000 one-call notifications per year. Third parties generate eighty-nine percent of the tickets. The remaining 10 to 15 percent represents homeowners, the operator's second-party contractors, and lastly, the operator's own forces.

The operator has analyzed the factors contributing to strikes on its system. Failure to maintain proper distance between heavy equipment and the pipe is the greatest contributing factor to pipeline strikes (representing 26 percent of total strikes). Failure to notify the operator through the one-call system is also a significant factor (17 percent of strikes). Insufficient marking of the facility, failure to properly locate the pipe, encroachment on abandoned facilities, and the failure of crews to utilize hand tools when in proximity to the pipe constitute the remaining percentage of incidents (11, nine, four, and three percent, respectively).

Operator I considers that it is difficult to distinguish between latent damage and system leaks that result from corrosion. Because of the nature of its system, the operator does not pig its distribution pipelines.

Damage not reported through the one-call system is discovered most frequently through the operator's periodic investigations for leaks or corrosion on its system. Operator I routinely performs leak surveys and also visits the pipeline right-of-way on a regular basis.

Pressure maintained on the distribution system is typically 60 psig or below. Generally, when an outside party damages a distribution line, the operator receives a call directly from the excavator.

When damage is found, Operator I immediately performs a repair. Distribution pipeline repairs are conducted to correct all problems that could impair pipeline service. The operator does not perform magnetic particle investigation on distribution pipe. A cutout repair may be performed on distribution pipe, if needed.

Transmission and storage pipe repairs are performed according to the pipeline repair manual criteria for the particular type of damage encountered.

Repairs to non-plastic pipe are conducted via the use of a clamp or clockspring device.
Cutouts are performed on plastic pipe, but typically not on steel.

Since the majority of the operator's system is comprised of lower-pressure (less than 100 psi) pipe, pressure is not reduced for repairs.

Mechanical damage generally comprises a lesser threat to the operator's system than corrosion. The operator reports that 80 percent of the nearly 5,000 leaks detected on its system within the last year were caused by corrosion. Only approximately 150 leaks were caused by excavations. A total of approximately 750 leaks were precipitated by miscellaneous other causes, such as anomalies at welds, the actions of the operator's own personnel, or effects from natural forces.

Operator I views enforcement of the one-call laws as an extremely important long-term measure to reduce the incidence of mechanical damage.

9.2.10 Operator J

Operator J's system is comprised of 15,000 miles of large-diameter interstate gas transmission pipeline. Portions of the company's system date from as early as the 1940s. While the nature and extent of mechanical damage to the operator's system varies according to geographic region, the majority of mechanical damage occurs on those pipe sections that traverse rocky, rugged terrain.

The operator employs a comprehensive program of preventative measures to reduce the incidence of mechanical damage to its system. Key elements include open-house meetings and other public communication initiatives, emergency responder and contractor group meeting participation, line-of-sight marker installation, right-of-way maintenance, right-of-way monitoring, routine system mapping updating, one-call notification system participation, and use of concrete-coated pipe at road crossings. Open-house meetings are held to inform residents that the company intends to conduct new pipeline construction or major pipeline repairs within a particular neighborhood and to provide education on the detection of gas leaks. In addition, annual mailings are sent to residents who are located within 1,000 to 1,300 feet from the pipeline. The mailings include a brochure that provides an overview of pipeline operations and address issues such as how to recognize leaks and the need to utilize the one-call notification system to alert the operator prior to excavating. An estimated 500,000 households are reached in this manner. The brochure incorporates a postage-paid postcard with questions to elicit feedback from residents. The operator reports that it receives a postcard reply from just one percent of brochure recipients, which the industry has discovered is the standard level of response when there are no giveaways attached to the responses. To validate residents' contact information (name and address), the operator conducts a telephone survey. The telephone survey results are used to determine, among other things, how well the public understood instructions for recognizing pipeline locations and for responding to a pipeline leak. The surveys are conducted on a subset of the public that receives the operator's public awareness brochures. The data also provides a clearer indication of the population segments whose members are actually reading the public awareness materials.

The operator participates in industry-sponsored group meetings with emergency responders and contractors/excavators at least once every three years and actively critiques the sessions for effectiveness.

Group meetings are facilitated by vendors (and in some cases state organizations) specializing in these events.

Line-of-sight markers are placed in Class 3 (densely populated) areas and high consequence areas (HCA) of the company's system. Line-of-sight markers are sometimes installed in less populated areas (Classes 1 and 2) but usually at locations that warrant them, such as road crossings. In addition to using standard markers, Operator J also employs 6-foot by 8-foot "Do Not Dredge" markers that are positioned along the pipeline right-of-way near commercially navigable waterways. Flat warning markers are installed along roadways in some densely populated areas as well, although the operator notes that these are often ignored or are more difficult to observe by the public and therefore have not proven very effective.

The operator firmly believes that a clear, clean right-of-way is essential to alert the public to the presence of the pipeline. The operator attempts to mow the right-of-way once a year in densely populated areas (Class 3 and HCAs). In less densely populated areas (Class 1 and Class 2 locations), the right-of-way is mowed every two or three years. Vegetative material is mowed to the ground surface and tree limbs that extend into the right-of-way are trimmed.

Operator J predominantly conducts fixed wing aircraft patrols along 99 percent of its on-shore system. Patrols via airplane on supply laterals are flown monthly. The mainline is flown weekly where construction activity is less frequent and twice weekly in more active locations. A small segment of the system near the Gulf of Mexico is flown by helicopter during ferrying flights to off-shore platforms. Foot patrols of the system are only performed in those areas over which it is impossible to fly, and are conducted on a weekly basis. If a pilot discovers evidence of encroachment within the right-of-way during aerial reconnaissance, he will immediately transmit a radio message to the ground crew. The ground crew staff will indicate whether or not they were previously aware of the activity and, if they were not previously alerted to it, when they intend to investigate it. If in-flight radio communication with the ground crew is not feasible, the pilot will communicate with the ground crew upon landing, via cell phone. Pilots documented encroachment observations through the use of an electronic form; however, the operator is transitioning to encroachment recordkeeping via an electronic database. Encroachment reports are also generated from data gathered through other means such as one-call tickets and routine ground observations.

Aerial mapping of the operator's entire system is performed every five years.

Operator J participates in the one-call notification system and anticipates that it receives 125,000 to 150,000 one-call tickets each year. Twenty percent of these tickets are generated by individuals actually performing work along the right-of-way and merit response. Eighty to 90 percent of the tickets are ultimately determined not to involve a threat of encroachment. The operator considers that it has done all it can do to reduce the number of calls to the one-call notification service, and that the one-call system must implement measures to better screen notifications. Following a one-call notification, the operator sends its own crews to mark the pipeline, to ensure that marking is done correctly. Generally, the operator finds that large contractors are not the parties who are responsible for the majority of encroachments and mechanical damage to the pipeline. Primary offenders are landowners (the largest percentage), followed by small landscaping firms, and fence installation companies. The operator also expresses surprise at the number of incidents caused by utility operators themselves.

Physical measures are also employed to protect pipeline integrity and include the installation of concrete-coated pipe at roadway crossings.

Accurate identification and characterization of deformations from mechanical damage are regarded by the operator as essential. The operator principally detects mechanical damage through its in-line inspection (ILI) program. The operator maintains a master agreement with one vendor who performs both caliper and magnetic flux leakage (MFL) investigations. For the last three years, nearly all of the ILI surveys conducted on the operator's system have involved the use of both types of ILI tools – geometry as well as MFL technology.

Topside and bottomside pipe deformations are identified for further investigation, as are all dents with gouges. A strain-based assessment of dents is routinely conducted, as required.

Making the right investigation decision is regarded as crucial. Operator J has formulated a standard operating procedure that guides the decision of whether to investigate a suspected anomaly. The operator generally excavates according to its decision tree.

Prescriptive requirements are clearly delineated for all mechanical damage in HCAs. The operator prefers to treat its entire system equally, whether a deformation is located within an HCA or non-HCA. However, if a defect is detected on a portion of the system that lies outside of an HCA, the operator prefers to extend its excavation response time to 30 days.

If a dent with a gouge is detected, damage repair will involve buffing of the gouge in accordance with the provisions of ASME B31.8. Pressure reductions for excavations are required; second reductions may be required for buffing out metal loss features. Three types of repair are most commonly performed: cutouts, coating and fillings, and clockspring repairs.

The operator does not employ markers to identify the pipe during backfilling operations. Rock shield is applied, if required.

Operator J has supported an MFL program for its entire pipeline system since the mid-1980s. While the company has evaluated MFL corrosion data for many years, its previous investigations were not as methodically defined for mechanical damage as they are at present. Four years ago, the operator requested its vendor to additionally conduct caliper investigations. Caliper tools are employed independently of MFL tools on the system to permit comparisons among the data. The operator reports that generally there is a high degree of correlation among the data gathered via these two technologies. However, the deformation data provided by each tool type are evaluated somewhat differently.

Both caliper and MFL tools are believed to adequately evaluate shallow dents with metal loss – that is, if a tool indicates that a particular dent is shallow or deep, and in a particular location, excavation usually corroborates the tool's report. The tools seldom fail to accurately characterize a deformation.

The operator is very satisfied with the performance of MFL tools. Caliper tools are regarded as useful for the sizing of dents – they help the operator to make screening decisions and therefore reduce the number of excavations that the operator must conduct. The operator finds that caliper data relating to shape and strain agrees with the results found during in-the-ditch examination.

MFL successfully detects bottomside pipe damage. The operator would also like to distinguish metal loss corrosion damage from metal loss gouges, but the company hasn't yet worked with ILI vendors to develop this capability. However, the presence of corrosion would not influence the decision to excavate until this discrimination capability is confirmed. If the data indicate that a dent contains metal loss (whether caused by corrosion or other means), the operator will always excavate to examine the deformation.

Stress corrosion cracking has been encountered very infrequently on the operator's system. Operator J does not employ crack tools to detect mechanical damage. The operator considers that its mechanical damage management program is thorough and that these tools are not needed.

Operator J conducts approximately 100 excavations relating to mechanical damage each year. Typically, more than three fourths of the dents encountered are bottomside dents; the remaining one quarter is comprised of topside dents, dents with metal loss, and dents at welds. After the operator's baseline program is completed in 2014, mitigation for existing mechanical damage will be completed and only investigation of recent (topside) damage should be needed.

Following a report or evidence of encroachment, Operator J performs exploratory excavations – even if there is no evidence of damage.

Only one of the operator's systems is unpiggable, but the operator has not yet employed the Direct Assessment approach to investigate mechanical damage on this system. Operator J is considering performing real-time monitoring of its system and has participated in applications of the acoustic monitoring method.

Prior to investigating suspected mechanical damage, an excavation decision is made – specifically, whether or not to excavate and how soon to perform the excavation. Operator J reduces pressure in preparation for all excavations relating to mechanical damage. The operator reduces pressure by 20 percent of the most recent high pressure level for suspected topside damage. Bottomside pressure reduction is more stringent – typically, pressure is reduced to 40 percent of the Specified Minimum Yield Strength or to 20 percent of the operating pressure, whichever produces the greatest pressure reduction.

Operator J rarely deviates from its established standard operating procedure. All excavations conducted very close to the pipe are performed manually. Rocks are routinely removed – rocks play an important role in bottomside damage.

Black-on-white magnetic particle inspection is utilized to investigate anomalies, such as areas of disbonded coating, and a profile gauge is employed to measure maximum strain.
Operator J regards the assessment of strain in the longitudinal direction as the critical pass/fail criterion, since it carries a small margin for error. Assessment of circumferential strain is believed not reliable or as useful, as it is difficult to obtain consistent field measurements and equally hard to interpret data. Consequently, the operator does not conduct circumferential strain evaluations.

In addition to performing strain calculations in the ditch, the operator utilizes radiographic methods to check for internal cracks within any deformation that exhibits a strain level of greater than six percent.

Grinding limitations are consistent with ASME B31.8 guidelines. If the buffing limit is reached, the problem segment is cut out. Approximately one anomaly in 20 must be cut out for this reason. The cut out process may require several days, depending on the circumstances. Recoating operations are determined by ASME B31.8 guidance.

Operator J is very concerned about topside dents that exhibit metal loss. Repair of these dents is considered urgent and is performed immediately. In the case of bottomside dents with metal loss, the excavation results frequently indicate original construction damage. Nevertheless, bottomside dents with metal loss are scheduled appropriately for excavation/assessment.

The operator has never employed steel sleeves to repair mechanical damage. Instead, following pressure reduction, clockspring devices are applied. Filler is also applied for dents, as required.

The operator is very satisfied overall with the performance of its ILI vendor, believing that the vendor overestimates strain value very little – not more than two percent. Improvement is always welcome, but this level of accuracy is adequate to make consistent excavation decisions.

Operator J believes that it has been extremely diligent in investigating and excavating mechanical damage and hopes that it can eventually reduce the number of excavations required.

The operator considers that future research must focus on improved tools to prevent the likelihood of mechanical damage and also to detect and characterize mechanically induced deformations. To streamline the reporting of planned excavations and more effectively allocate company resources, the operator believes that improvements are needed to enhance one-call notification system operation and reduce the number of tickets unnecessarily generated. Greater enforcement of the one-call laws is also required.

The use of unmanned vehicles for right-of-way monitoring is an area of research regarded by the operator as very promising.

Operator J is currently participating in a pilot study of the "Threat Scan" real-time monitoring system. The technology, in place for a year or so, has proven generally effective, although the operator notes that the system has yielded a few false reports, most likely because of its increased sensitivity.

The operator advocates the development of improved tools to more accurately characterize and evaluate deformations – specifically, to estimate the severity of dents and discriminate among the types of dents and depth of metal loss. Improved ILI technology is also regarded as needed to locate cracks within dents.

9.3 Summary

Operator experience with mechanical damage is significant, although the risk is determined in large part by system attributes as well as location. The majority of the operators interviewed acknowledged that mechanical damage poses a serious and ongoing threat to the integrity of their pipeline systems and, consequently, to the safety and health of not only operator and excavator personnel, but the general public as well. However, a few operators whose systems are located in non-urban areas report that corrosion and/or stress corrosion cracking remains the greatest threat to their systems.

While several operators identify rock damage as the predominant form of mechanical damage encountered (again, affected by pipeline attributes and/or location), most operators report that human intervention is the primary cause of mechanical damage to their pipelines. Entities who damage pipelines include operator forces (first parties), excavation contractors hired by the operator or other utility companies (second parties), and private citizens and other landowners (third parties). Failure to follow one-call laws underlies the majority of strikes. A significant proportion of strikes is caused by other utility companies; a large percentage is caused by third parties who fail to follow one-call notification laws.

All operators cited the prevention of mechanical damage as a critically important focus in the industry, and all belong to one-call organizations, as they view such participation as vital to incident reduction. Increased enforcement of the existing laws for one-call notification and the imposition of stricter penalties for violators are regarded by the operators as integral to mitigating the threat of mechanical damage. Some operators believe that second party violators, oftentimes currently exempt from one-call compliance, must be required to adhere to one-call notification requirements. Increasing public awareness through communication initiatives is likewise considered essential to reduce pipeline strikes. Each operator has in place a public awareness program that includes measures such as placing markers and warning tape along the pipeline right-of-way. Some feel the need for increased interactions and discussions with contractors on planned excavations.

In addition to prevention, detection and mitigation of suspected mechanical damage are primary areas of concern. Many operators routinely conduct aerial and foot patrols along their right-of-way to check for evidence of encroachment.

All operators utilize in-line inspection (ILI) tools, but point out the unreliability of ILI tools in accurately detecting, assessing, and characterizing mechanical damage. Standard geometry tools alone cannot consistently address operators' need to know whether to excavate a detected anomaly, and consequently, many unnecessary and costly excavations are conducted as a precautionary measure. Improved results have been realized through the use of combination tools that incorporate both magnetic flux leakage (MFL) and geometry technologies. However, additional improvements in ILI technology are believed necessary to enable operators to better identify instances of mechanical damage that pose a valid threat and target areas of concern for excavation. Some operators think that an effective method for in-the-ditch assessment (e.g. strain analysis) is required to govern the decision-making process for damage repairs.

Mitigation decisions and practices adhere to and often exceed minimum regulatory requirements and recommended guidance. Type A sleeves are used to mitigate plain dents. Dents with gouges, other metal loss defects, or cracks are most often repaired through the application of Type B pressure-containing metal sleeves. Cut-outs are performed as needed to repair severely damaged pipe segments.

10 Regulatory Practices – United States and Foreign

10.1 U.S. Regulations and Industry Standards

Federal regulations require pipeline operators to identify and address integrity threats to their pipeline systems which, in nearly all cases, include the threat posed by mechanical damage. Pipeline companies and their regulators must determine if the threat assessment, prevention, detection, characterization, evaluation, and mitigation measures that pipeline operators include in their Integrity Management Programs are adequate. For mechanical damage in particular, emphasis is placed on proactive prevention measures, as opposed to risk evaluation and hazard mitigation.

In the United States, the Pipeline and Hazardous Material Safety Administration's (PHMSA) Office of Pipeline Safety (OPS) is responsible for regulating pipelines. As early as the 1940s, pipelines began to pose serious problems for excavators and others involved in construction. As the number of underground facilities has increased, so has the probability of incidents caused by mechanical damage. Since 1968, the federal government has attempted to address these problems. The issue reached a critical point in the late 1990s after a series of pipeline accidents. On September 27, 1996, New Jersey Rep. Bob Franks delivered speech to the House of Representatives reflecting the concerns:

> *[T]he existing regulatory scheme governing pipelines is inadequate. It is frighteningly clear that not enough attention or resources are being dedicated to confronting the most significant dangers relating to pipelines. While statistically one may be more likely to be struck by lightning than die in a pipeline accident, the potential for large-scale fatalities from a pipeline explosion are frightening and real.*

Rep. Franks spoke in support of S.1505 known as the Accountable Pipeline Safety and Partnership Act of 1996. The 1996 Act and those that came after it constituted the first real steps at apportioning liability and mandating the creation of "one-call" centers. In compliance with federal regulations, each state has enacted its own one-call damage-prevention statute governing the activities of excavators and underground utility owners and operators, which establishes notification centers and sets forth the procedures and timelines for one-call notification. However, statute details vary significantly from one state to another. Some states require participation by every utility, while others do not. Some states impose affirmative duties on designers and other construction professionals, in addition to excavators. For example, Colorado state law specifies that "Every owner or operator of an underground facility in this state shall join the notification association pursuant to Section 9-1.5-105." The Colorado law is one of the most inclusive with respect to the mandating of one-call participation and assignment of legal responsibility.

Statutes generally provide for penalties and/or specify utility liability in the event of nonparticipation. In voluntary participation states, excavators must contact nonparticipating utilities. South Carolina's statute, for example, provides that excavators must serve notice on "such association and each operator that is not receiving the services of the association." Only a few states still have statutes that permit voluntary participation, and the number is likely to decline in the next few years. For instance, at one time, New Mexico's statute identified participation in the one-call system as voluntary. Recently, the statute was changed, and the law now requires one-call participation by pipeline facility owners and operators.

Because there are at least 50 different one-call statutes, it is critical for excavators and other construction professionals to understand the one-call laws that apply to each of their projects. Contrary to what the name implies, excavators are assigned numerous duties under these statutes. One phone call alone may be insufficient to address the range of their responsibilities and may in fact constitute non-compliance. In addition, one-call centers typically will not provide details about or explain excavation laws. Accordingly, individuals whose job performance is subject to one-call statute compliance should make a point of learning the laws applicable to their particular projects.

Congress reinforced the strength of the one-call initiative by passing the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006. The PIPES Act created an incentive for states to upgrade the effectiveness of their damage prevention programs by offering grants to improve essential program elements. Several states, including Virginia and Texas, have already revised and strengthened their programs.

If the preventative measures fail and mechanical damage occurs, current regulations provide simple acceptance criteria for evaluating and determining the need to remediate dents, based primarily on depth and location. These criteria do not consider complex, or interactive, behavior. In addition, industry standards and regulations do not provide guidance for establishing and assessing initial measures to reduce an integrity threat before final mitigation measures can be employed. Nor do they set forth criteria that establish a time frame within which to mitigate an integrity threat – i.e., there is no generally recognized or approved procedure that can be employed to evaluate the remaining strength of a pipe section which has corrosion in a dent. Finally, industry standards and regulations do not provide guidance for evaluating the relative effectiveness of various mechanical damage management options in reducing or eliminating integrity threat.

10.1.1 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline

Subpart L, “Operations,” addresses various items related to pipeline damage, including Continuing Surveillance (§192.613), Damage Prevention Programs (§192.614), Emergency Plans (§192.615), and Public Awareness (§192.616). Section 192.615 is of particular interest as it specifies that, in most cases, operators whose buried pipelines may be accessed by excavators or other workers must develop and implement a written program to prevent excavation damage to their pipelines. Compliance may be, and usually is, met through participation in a qualified one-call system, and the code specifies high-level minimum requirements for such qualification.

The requirement to comply with damage prevention program requirements is found in other sections of 49 CFR Part 192, specifically:

For Type B gathering lines, §192.9(d) specifies the following[1]:

- (3) - Carry out a damage prevention program under §192.614
- (4) - Establish a public education program under §192.616

For new construction, §192.313 specifies the following:

- (a) - Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315, must comply with the following:
    - (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

Under the regulations for integrity management programs, §192.935(b)(1) states:

> (1) *Third party damage*. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

[1] Only guidance relating to mechanical damage was been included.

(i) Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under 49 CFR Part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

For pipelines operating under 30 percent, section §192.935(d) states an operator must:

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

10.1.2 Pipeline Safety Improvement Act of 2002

President George W. Bush and the 107th Congress passed the "Pipeline Safety Improvement Act of 2002" into law on December 17, 2002. Upon passing the bill into law, it became Public Law 107-355 which can be found in its entirety at http://www.gpoaccess.gov/plaws. The law required the U.S. Department of Transportation (DOT) to issue regulations prescribing standards for operator's adoption and implementation of new transmission integrity management programs. The law set forth minimum requirements for integrity management programs for gas transmission pipelines located in "High Consequence Areas" (HCAs.) The law also requires that operators of gas transmission pipelines complete baseline integrity assessments for covered segments within 10 years of enactment (by December 12, 2012.) The law also requires that 50 percent of covered segments be completed within 5 years of enactment (by December 7, 2007.) Finally, the law requires that covered segments be re-assessed at least every 7 years. The DOT published the federally-mandated regulations at 49 CFR Part 192 Subpart O.

Under 49 CFR Part 192 Subpart O, §192.917 includes third party damage and outside force damage as threats to pipeline integrity that must be identified and assessed in an operator's integrity management program. These are considered as time independent threats. Subpart (1) of §192.917(e) requires that an operator utilize data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage.

If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

49 CFR Part 192, Subpart O §192.933 addresses actions that an operator must take to address integrity issues (including mechanical damage). Temporary and long-term pressure reductions are called for under conditions in this section. The schedule for evaluation and remediation of integrity threat conditions is contained in Subparts (c) and (d). Under §192.933(d)(1)(ii), a dent with any indication of metal loss, cracking or a stress riser, is considered a *immediate repair condition,* requiring evaluation and remediation scheduled as per ASME/ANSI B31.8S, Section 7, as well as a temporary reduction in operating pressure or shut down of the pipeline until repairs are complete. Section 192.933(d)(2) addresses *one-year conditions*, meaning that remediation of the defect must be within one year of discovery of the following conditions:

> (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
>
> (ii) A dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

Finally, §193.933(d)(3) addresses *monitored condition,* meaning that an operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. These conditions, indicative of mechanical damage, include:

> (i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).
>
> (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.
>
> (iii) A dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

10.1.3 49 CFR Part 195 – Transportation of Hazardous Liquids by Pipeline

Subpart F Operation and Maintenance addresses various items related to pipeline damage. Section 195.442 Damage Prevention Program contains almost identical language to that of §192.614, except that it also briefly addresses some factors that differentiate gas from liquid pipelines (e.g., class location).

Appendix C to 49 CFR Part 195 gives guidance to help an operator implement the requirements of the integrity management program rule in §195.450 and §195.452.

Section 2.B, VII defines conditions that may impair a pipeline's integrity.

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. Subpart (4) of §195.452(h) prescribes special requirements for scheduling remediation depending on the severity of the integrity issue. Mechanical damage threats conditions that require *immediate repair* (including temporary pressure reduction or shutdown of the pipeline until the repairs are complete) under Subpart (i) of §195.452(h)(4) include: (only guidance relating to mechanical damage has been included here and some numbering is skipped)

(A) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6 percent of the nominal pipe diameter.

Mechanical damage threats conditions that require scheduling evaluation and remediation within 60 days of discovery of conditions (i.e., *60- day conditions)* under Subpart (ii) of §195.452(h)(4) include:

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3 percent of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline with a depth greater than 6 percent of the pipeline's diameter.

Mechanical damage threats conditions that require scheduling evaluation and remediation within 180 days of discovery of conditions (i.e., *180-day conditions)* under Subpart (ii) of §195.452(h)(4) include:

(A) A dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6 percent of the pipeline's diameter.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(I) A gouge or groove greater than 12.5 percent of nominal wall.

10.1.4 49 CFR Part 190 - Penalties

49 CFR Part 190.229(e) under Subpart B – Enforcement specifies that penalties for not using a one-call notification system or not heeding location information or markings includes a fine, imprisonment for up to five years, or both, if the person:

- Knowingly and willfully engages in an excavation activity
  - Without first using an available one-call notification system to establish the location of underground facilities in the excavation area; or
  - Without paying attention to appropriate location information or markings the operator of a pipeline facility establishes; and
- Subsequently damages
  - A pipeline facility that results in death, serious bodily harm, or actual damage to property of more than $50,000;
  - A pipeline facility, and knows or has reason to know of the damage, but does not report the damage promptly to the operator of the pipeline facility and to other appropriate authorities; or
  - A hazardous liquid pipeline facility that results in the release of more than 50 barrels of product.

Penalties under this subsection may be reduced in the case of a violation that is promptly reported by the violator.

10.1.5 OSHA Regulations, 1926.651, Specific Excavation Requirements

The Occupational Safety and Health Administration (OSHA) specified that the estimated location of utility installations, such as sewer, telephone, fuel, electric, water lines, or any other underground installations that reasonably may be expected to be encountered during excavation work, shall be determined prior to opening an excavation. Utility companies or owners shall be contacted within established or customary local response times, advised of the proposed work, and asked to establish the location of the utility underground installations prior to the start of actual excavation.

When utility companies or owners cannot respond to a request to locate underground utility installations within 24 hours (unless a longer period is required by state or local law), or cannot establish the exact location of the installations, the excavator may proceed, provided that caution is exercised and that detection equipment or other acceptable means to locate utility installations is used.

When excavation operations approach the estimated location of underground installations, the exact location of the installations must be determined by safe and acceptable means.

Penalties are also established for failure to follow these requirements.

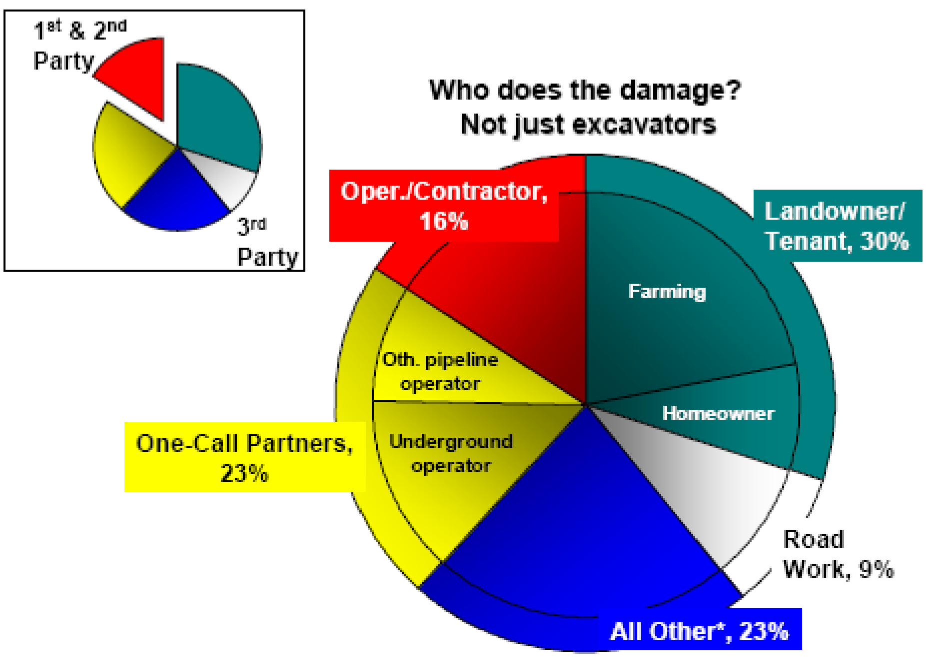
10.1.6 Effectiveness of Current Regulations

An estimated two-thirds of pipeline excavation damage is caused by third parties. The problem is compounded if the pipeline damage is not promptly reported to the pipeline operator so that corrective action can be taken. As discussed in Chapter 4, third-party excavation damage is the single greatest cause of accidents involving natural gas distribution pipelines. It is also a leading cause of damage among natural gas transmission and hazardous liquid pipelines.

For years, the U.S. Department of Transportation has been continuously challenged to improve the safety of underground pipelines through the reduction of third-party excavation damage. In the late 1990s, Congress gave the Research and Special Programs Administration (the Department's former agency with oversight over pipeline safety), one of the largest assignments it had ever undertaken: determining the most effective damage prevention practices to end third-party damage as the overall major cause of pipeline accidents. The process involved utilizing an enterprise approach to reach consensus among more than 160 industry and government professionals who volunteered their time to create the Common Ground Study in 1999, identify best practices to reduce underground facility damage, and, eventually, form the Common Ground Alliance (CGA) in 2000. The work of the CGA public/private partnership, which reflects a collaborative approach, became the catalyst for all subsequent damage prevention efforts. Throughout its existence, the CGA has been a leading advocate of the one-call concept and has emphasized the need to remind all underground facility owners to correctly locate their utilities before excavation or construction activities commence.

Despite these efforts, excavation damage remains a significant threat, which has prompted further research both in the identification of potential causes, as well as in the development of additional procedures for third-party damage prevention. When the oil pipeline industry developed the survey for its voluntary spill reporting system – known as the Pipeline Performance Tracking System (PPTS) – it also recognized that damage to pipelines, including that resulting from excavation, digging, and other impacts, is also precipitated by operators ("first parties") and their contractors ("second parties").

One of the insights from PPTS was the number of incidents caused by entities that actually participate in one-call programs. In the chart below, "one-call partners" include the utility operators who pay for one-call systems – the very entities that receive shown, these entities actually caused 23 percent of the excavation damage incidents over the period from 1999-2006.



Onshore pipeline spills where: release occurred at the time of damage, and involving 5 barrels or more, or death, fire, injury, or explosion.
**"All Other" includes residential/commercial development, waterway, railroad, and other party or activity.*

Figure 10.1 – Pipeline Performance Tracking System (PPTS) Advisory 2008-4
http://committees.api.org/pipeline/ppts/docs/Advisories/2008/Excavation%20Damage%20Overview%20Final.pdf

From Figure 10.1, it can be seen that almost 10 percent of the incidents were caused by "other pipeline operators" – that is, gas transmission and liquids pipeline operators themselves. In fact, some of the liquids pipeline operators could be PPTS participants who damaged the pipeline of another PPTS operator in the shared right-of-way. The fact that operators who share data and other technical information resources and are participating in the development of prevention strategies nonetheless continue to damage each other's pipelines demonstrates that damage prevention is a complex issue.

Finally, the graph illustrates the role of operators and their contractors in excavation-related incidents. In these cases, the PPTS operator who reports the incident has damaged its own pipeline, or the pipeline has been damaged by the operator's own contractor. These incidents represent 16 percent of all excavation damage incidents that PPTS records as "operator error."

For the incidents involving third parties, PPTS also records whether the excavator notified a one-call association prior to undertaking the planned activity. It is significant that in more than 50 percent of the incidents, one-call associations were not contacted first.

One-call partners accounted for 27 percent of the third party incidents. Failure to use the one call system was named as the primary cause of one-third of these incidents. In addition, failure to take responsible care, to respect the instructions of the pipeline personnel, and to wait the proper time accounted for another 50 percent of the incidents. The data suggest that even when a one-call association is contacted, a misstep may occur that causes a product release, which is yet another confirmation of the complexity of damage prevention and the need for not only more emphasis on use of the one-call system, but also additional focus on alternative and emerging technologies.

10.1.7 PHMSA Research

PHMSA has established and is implementing an effective and collaborative pipeline safety research and development program. The program systematically coordinates and co-funds with all major relevant federal and state agencies and with industry trade organizations representing hazardous liquid, natural gas transmission and distribution pipelines. Collaborative research on mechanical damage is fostering development of new technologies to improve safety performance and to more effectively address regulatory requirements; strengthening related national consensus standards; and improving the state of knowledge of pipeline safety officials so that industry and regulatory leaders can use this knowledge to better understand safety issues and to make better resource allocation decisions leading to improved safety performance.

Table 10.2 shows funding for research efforts by the objectives of developing technology, strengthening standards and promoting knowledge. It should be noted that any project can be relevant to more than one objective. Mechanical damage issues are a constant theme at collaborative R&D forums and workshops. The PHMSA program is committed to generating the best projects conducted by the best researchers that produce the desired impacts for preventing, detecting and characterizing mechanical damage.

Table 10.2 PHMSA Research Efforts

Objective	Projects	PHMSA	Industry	Total
Strengthening Standards	42	$12.56M	$16.57M	$29.14M
Technology Development	54	$25.75M	$28.85M	$54.60M
Knowledge Documents	103	$25.09M	$38.20M	$63.29M

(http://primis.phmsa.dot.gov/rd/splan.htm)

PHMSA has organized activities in the pipeline safety research and development (R&D) program around seven R&D program categories. The program categories reflect the responsibilities of DOT in the Five Year Interagency R&D Program Plan and guidance from pipeline experts and stakeholder groups.

A full breakdown of the program strategy and performance is available at http://primis.phmsa.dot.gov/rd/ and is a valuable tool in understanding collaborative efforts in addressing mechanical damage.

Table 10.3 Research Strategies & Objectives

Program Category	Objectives	Amount (Millions of U.S. Dollars)		
		PHMSA	Industry	Total
Damage Prevention	Strengthening Standards	$0.21	$0.47	$0.68
	Technology Development	$1.76	$1.08	$2.84
	Knowledge Documents	$0.28	$0.54	$0.82
Pipeline Assessment and Leak Detection	Strengthening Standards	$4.79	$5.25	$10.05
	Technology Development	$16.61	$16.79	$33.41
	Knowledge Documents	$7.50	$10.92	$18.42
Defect Characterization and Mitigation	Strengthening Standards	$2.10	$2.83	$4.93
	Technology Development	$0.47	$1.02	$1.49
	Knowledge Documents	$4.00	$5.05	$9.05
Improved Design, Construction and Materials	Strengthening Standards	$3.83	$6.39	$10.22
	Technology Development	$2.00	$3.24	$5.25
	Knowledge Documents	$5.91	$12.00	$17.92
Enhanced Operation Controls and Human Factors Management	Strengthening Standards	$0.00	$0.00	$0.00
	Technology Development	$0.00	$0.00	$0.00
	Knowledge Documents	$0.53	$0.49	$1.02
Risk Management and Communications	Strengthening Standards	$0.00	$0.00	$0.00
	Technology Development	$0.00	$0.00	$0.00
	Knowledge Documents	$0.03	$0.03	$0.07
Safety Issues for Emerging Technologies	Strengthening Standards	$0.21	$0.22	$0.43
	Technology Development	$0.00	$0.00	$0.00
	Knowledge Documents	$0.35	$0.26	$0.61

(http://primis.phmsa.dot.gov/rd/splan.htm)

10.2 Canadian Regulations and Industry Standards

10.2.1 Canadian Regulatory Framework

In Canada, the National Energy Board (NEB) is responsible for promoting the safe construction and operation of federally regulated pipelines (NEB, 1997). NEB regulates pipelines crossing interprovincial and/or international boundaries of all the provinces and territories west of the Atlantic region. Pipeline systems which are wholly contained within a province typically fall under that province's regulatory jurisdiction.

The primary responsibility for the safety of pipelines rests with the owner. Companies that are subject to the NEB's jurisdiction must apply to NEB prior to constructing or modifying their pipelines. NEB considers relevant safety issues relating to the design, construction, control, and operation of the pipeline system.

The Onshore Pipeline Regulations set out the minimum requirements for all stages of a pipeline's life cycle. The Canadian Standards Association (CSA) pipeline standards provide a technical basis for the Onshore Pipeline Regulations, setting out the minimum requirements for design, construction, operation, and abandonment of pipelines.

Damage caused by third parties during construction and excavation activities is recognized as one of the principal threats to pipeline integrity. The NEB's Pipeline Crossings Regulations (NEB, 2005) establish specific responsibilities for persons intending to excavate or perform construction near pipelines, as well as the responsibilities of the pipeline company.

NEB conducts regular on-site safety inspections. NEB inspectors are empowered to issue orders that could require a company to suspend hazardous activities and/or to take measures to ensure the safety of people or the protection of the environment.

NEB also actively monitors accidents and may evaluate the implications of a major accident on a pipeline company's operations and/or on current safety regulations and standards. Accidents which occur during the operation of a pipeline are also reportable to the Transportation Safety Board of Canada (TSB); TSB has the authority to issue recommendations to the Minister of Natural Resources.

10.2.2 Canadian Industry Standards

The primary design standard for highly rated oil and gas pipelines in Canada is CSA Z662 (2003). The fifth edition was published in June 2007. The requirements of the standard are considered to be adequate under the operating conditions normally encountered in the oil and natural gas industry. The standard is intended to establish essential minimum requirements for the design, construction, operation, and maintenance of oil and gas industry pipelines, including gas storage lines.

The standard is goal-setting; it sets out the objectives to be achieved but does not dictate how they are to be met, placing the obligation on the owner to demonstrate compliance. The standard includes a non-mandatory annex containing guidelines on the application of risk assessment to pipelines.

In line with the goal-setting approach, the standard states "Operating companies shall periodically patrol their pipelines in order to observe conduct and activities on and adjacent to their rights-of-way that may affect the safety and operation of the pipeline," and that "the frequency of pipeline patrolling shall be determined by considering such factors as operating pressure, pipeline size, population density, service fluid, terrain, weather and land use." Also, "special consideration shall be given to the inspection and maintenance of pipeline crossings."

Concerning the evaluation and repair of dents, the standard states:

Dents shall be inspected using visual and mechanical measurement methods capable of determining the location of the dent with respect to mill and seam welds, the depth and shape of the dent, and the presence of gouges and grooves. Where considered appropriate, non-destructive methods capable of detecting cracks and internal corrosion imperfections shall also be used.

The following dents shall be considered to be defects unless determined by an engineering assessment to be acceptable:

- Dents that contain stress concentrators (gouges, grooves, arc burns or cracks)
- Dents that are located on the pipe body and exceed a depth of 6 mm in pipe 101.6 mm OD or smaller or 6% of the outside diameter in pipe larger than 101.6 mm OD
- Dents that are located on a mill or field weld and exceed a depth of 6 mm in pipe 323.9 mm OD or smaller or 2% of the outside diameter in pipe larger than 323.9 mm OD
- Dents that contain corroded areas with a depth greater than 40% of the nominal wall thickness of the pipe
- Dents that contain corroded areas having a depth greater than 10%, up to and including 40%, of the nominal wall thickness of the pipe and a depth and length that exceeds the maximum allowable longitudinal extent determined in accordance with ASME B31G.

The standard goes on to prescribe the types of repair (grinding, or the use of steel or composite reinforcement sleeves) and the limitations on their applicability for each type of dent defect.

10.3 United Kingdom (UK) Regulations and Industry Standards

10.3.1 UK Regulatory Framework

In the UK, the current regulatory framework pertaining to the design, construction, and safe operation of pipelines stems from Statutory Instrument No. 825 of the Pipeline Safety Regulations (1996) and associated guidance on the regulations and is enforced by the Health and Safety Executive (HSE) Hazardous Installations Directorate. The regulations are goal-setting; they set out the objectives to be achieved but do not specify how they are to be met, and they permit risk-based approaches. The operator is held responsible for complying with the requirements.

In terms of safety management, the regulations require the operator to identify all hazards relating to the pipeline that could potentially cause a major accident, to evaluate the risks arising from the hazards, to establish operational arrangements and procedures to ensure that the risk of a major accident is as low as reasonably practicable, and to establish adequate auditing/reporting processes.

The Gas Safety Management Regulations (1966) require operators whose pipelines are used to convey natural gas to prepare “safety cases” that verify they are safely managing the flow of gas. The safety cases must be accepted by HSE before gas can be transported.

10.3.2 Industry Standards

The international code ISO 13623 (2000) is basically a goal-setting standard with specific criteria only for pressure containment and stress calculation. In Europe, this standard has developed into EN 1594 (2000) for natural gas supply systems with operating pressures exceeding 16 bar and EN 14161 (2003) for all other petroleum and natural gas industry pipelines. The UK equivalent standards are BS EN 1594 (2000) and BS EN 14161 (2003). These standards provide recommendations for the design, selection of materials, construction, testing, operation, maintenance, and abandonment of pipeline systems used for transport in the petroleum and natural gas industries.

Like ISO 13623, EN 1594 and EN 14161 are goal-setting standards and hence require supplementary guidance for use in specific situations. In the UK, and elsewhere in Western Europe, the PD 8010 (2004) Code of Practice for Pipelines provides additional recommendations and guidance, primarily for the oil and gas industry. In addition, the standard IGE TD/1 (2004) is widely accepted in the UK as a national standard for the design, construction, and operation of natural gas pipelines with operating pressures above 16 bar.

Standards such as IGE TD/1 contain general guidance for mechanical damage prevention, detection, assessment, and repair. The operator is required to develop specific provisions to demonstrate compliance with pipeline safety and integrity requirements, taking factors into account such as the pipeline's size and product, the location and population density, the surrounding environment, and land use. The specific provisions are prescribed in in-company procedures, but are not made public. However, in many instances they are understood to be closely aligned with the guidance on damage prevention and safe proximity developed by Advantica (Acton, 1998), and the guidance on assessing the significance of mechanical damage developed by the European Pipeline Research Group. (Roovers, 1999)

10.4 European Regulations and Industry Standards

10.4.1 The European Pipeline Safety Instrument

Under the European Commission's Seveso II Directive (96/82/EC), operators of all major plants are obliged to establish and maintain a safety management system, but this obligation does not specifically extend to pipelines. Recognizing that pipelines have the potential to produce major accidents, the European Commission undertook a study in 2000 to collate and review the current national regulations. The study "Assessment of Requirements on Safety Management Systems…" (Papadakis, 2000) revealed considerable variation in the nature of existing pipeline safety legislation across member states, ranging from more restrictive regulations prescribing well-developed systems in some countries to fewer and less restrictive regulations – or none at all – in others. The study recommended a mandatory goal-oriented European Instrument, based on the principles of the Seveso Directive, as the most appropriate solution.

A European Commission Task Group has been established to consider developing such an instrument. However, many of the major gas pipeline operators in individual states are reluctant to adopt a Europe-wide instrument, preferring to retain their national instruments ("…Unification of European Technical Legislation..." [Hec, 2007]).

10.4.2 European National Safety Instruments

In Norway, all pipeline safety issues are dealt with by the Petroleum Safety Authority (PSA), which came into being in 2004 when it was split from the Norwegian Petroleum Directorate. PSA is the nation's designated safety authority for the planning and construction of pipelines and also performs a role in the supervision of operators. Operators are required to report any incidents to PSA.

In Germany, pipeline safety, alongside the safety of other installations, is the responsibility of the government Department for Economics and Technology. The national Law for High Pressure Gas Pipelines (operating above 16 bar), "Verordnung…" [Department for Economics and Technology, 2006]) is administered by each individual State Authority for Energy.

In Holland, the government recently created a Task Force on pipeline safety in response to a growing consensus that shortcomings exist (Ruessink, 2005). The recent major gas pipeline accident at

Ghislinghem in Belgium served as the impetus for a new in-depth look at the regulatory aspects of pipeline safety.
The Task Force has found:

- The legal framework with respect to pipeline construction is rather weak
- Essential data on pipelines is scattered and poorly accessible
- Responsibilities in organizing, administering, and enforcing pipeline integrity safety regulatory measures are not clearly delineated.

The Dutch government has given responsibility to the Ministry of Housing, Spatial Planning, and the Environment to make improvements in line with the recommendations of the Task Force. The government has emphasized that control by the authorities should promote the safety management systems that many operators either have put in place or are planning to implement. The Task Force is currently consulting with stakeholders to identify appropriate policies.

In Denmark, energy policy as a whole is directed and administered by the Danish Energy Authority. The authority supervises the Offshore Installations Act, the Pipelines Act, and the Act on the Continental Shelf. Collectively, these acts pertain to occupational safety, health, and the working environment in connection with offshore oil and gas activities and onshore pipelines from oil and gas fields in the North Sea.

10.4.3 European Standards

As was indicated above, the principal European standards for potentially hazardous pipelines are EN 1594 (2000) for natural gas supply systems with operating pressures exceeding 16 bar, and EN 14161 (2003) for all other petroleum and natural gas pipelines. These are goal-setting standards, providing recommendations for the design, construction, operation, maintenance, and abandonment of pipeline systems used for transport in the petroleum and natural gas industries in states within the European Commission.

Supplementary guidance is provided to facilitate the application of EN 1594 and EN 14161 for specific purposes. The PD 8010 (2004) Code of Practice for Pipelines is widely used in Europe for oil and gas industry pipelines, alongside the DNV Subsea Pipeline Standard OS-F101 (2007), for the assessment of defects, including mechanical damage.

Individual European countries have national standards that supplement EN 1594 and EN 14161. For example, in Holland the standard for pipelines is NEN 3650 (2003), while in Ireland gas pipelines are built in accordance with IS 328 (2003); in Germany, pipelines are designed to EN 1594 but with a higher safety factor, 1.9 as opposed to 1.5-1.6. These national standards are equivalent in overall approach, but use slightly different formulations to calculate stress, apply safety factors, and determine safe proximity zones.

Most of the European standards and national supplementary standards include generalized provisions for preventing damage to pipelines and for assessing the structural significance of any defects and damage that occur. The operator is required to develop specific provisions to demonstrate compliance with the pipeline safety and integrity requirements, taking into account the pipeline's attributes (size, product, population density, local environment and land use, etc.). Many of the major European gas pipeline operators base their approach to mechanical damage on the collective experience of the European Gas Incident Group, together with the guidance for preventing as well as assessing the significance of various types of dent and gouge damage developed by EPRG.

The EPRG guidance is generally provided in two forms: a “rule-of-thumb” method for initial screening and preliminary assessment and a “best available” method for detailed case-by-case evaluation. Rules have been developed for determining a pipe’s resistance to penetration by various excavation and drilling tools, and for assessing the pressure-containment capability of various non-penetrating dents, gouges, and combined dent-gouge features.

Much of the EPRG guidance for assessing the pressure-containment capability of mechanically damaged pipe has been reviewed, updated, and incorporated into the *Pipeline Defect Assessment Manual* (PDAM), developed by an international joint industry group. Some of the resulting guidance has been published (Cosham and Hopkins, 2002, 2003, 2004). The PDAM methods are increasingly being used by operators of oil and gas pipelines to support their company procedures for damage management.

10.5 Summary

Pipelines are regulated by numerous government codes and standards. Those directly related to mechanical damage are covered. Other regulations exist for broad range of issues indirectly related to mechanical damage, pressure reductions, repair requirements, etc. Finally, it is necessary for all the industry standards and regulations to provide sufficient guidance for evaluating the relative effectiveness of various mechanical damage management options in reducing or eliminating integrity threat.

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11 Research Gap Analysis

11.1 Scope

Mechanical damage to both liquid and gas transmission pipeline is a significant problem. A considerable amount of research has been conducted to address mechanical damage as it relates to pipeline integrity. Increasing awareness within the industry as well the public regarding safety of pipelines has highlighted the need for more improvements.

For past several decades, Pipeline Research Council International (PRCI) has studied mechanical damage extensively. Research concerning the effect of mechanical damage on transmission pipeline serviceability has focused on full-scale experimental studies directed at better quantifying factors controlling damage and criteria to assess its severity and other effects. Likewise, work within the European Pipeline Research Group (EPRG) traces back decades through work undertaken by both contractors and member gas companies. Other work has been done in the United States, Canada, Europe, Japan, Australia, and elsewhere.

This gap analysis covers mechanical damage to onshore pipelines transporting oil, gas, and hazardous liquids. Its objectives were to identify outstanding gaps related to prevention, detection/characterization, assessment, and mitigation. The analysis focused on existing knowledge and state-of-the-art tools and technology as they relate to the management of mechanical damage of pipelines.

This analysis included reviews of published literature, proprietary reports, information from two gap analyses commissioned by PRCI, the outcome of the Pipeline and Hazardous Materials Safety Administration (PHMSA) Workshop on Mechanical Damage, PRCI's Research Roadmap for Mechanical Damage, and issues raised during the Operator Survey conducted as part of this Study (Leis and Hopkins, 2003, May and July; Leis and Hopkins, 2004; PHMSA, 2006; Fuglem, 2007; Batte, 2007; and Michael Baker Jr., Inc., 2008).

The gap analysis was conducted with an aim to develop and improve operating guidelines and codes that ensure the safe operation of pipelines around the world. To ensure future developments address critical needs, the gaps associated with mechanical damage prevention, detection/characterization, assessment, and mitigation are discussed below.

11.2 Prevention

The prevention of mechanical damage is rightly seen as the most important aspect of the damage management process, having an immediate impact in reducing the frequency of occurrence of fatalities, injuries, and damage to the environment and property. Effective methods of preventing damage include built-in design features, active and passive monitoring of the right-of-way, accurate knowledge of the pipeline's location, one-call systems to alert both operators and contractors when there is in-ground activity, and education of landowners, land-users, and the general public concerning the dangers of interfering with pipelines. Such methods rely on a combination of technology, procedures, and people to achieve their aims.

Damage prevention is not fully effective because such ideals are not always met. Areas for further development include:

- Improved public awareness guidance for preventing mechanical damage, based on better understanding of human behavior and the effective use of change management practices.
- Improved understanding of the factors that determine the frequency of occurrence of mechanical damage (such as geographical location, terrain, and changes in land use or population density over time), to help operators better focus their prevention strategies.
- Effective risk-based guidance to prioritize pipeline segments based on mechanical damage threat.
- Development of more effective processes and technologies for monitoring right-of- way intrusions and infringements, to reduce the time between intrusion and response.
- Technology that enables improved communication (communication that is faster, more reliable, and more accurate) between the operator and those working in the right-of -way.
- Technologies for better identification of pipelines in high consequence areas.
- Development of operator guidance on the effectiveness of damage prevention methods, enabling selection of optimized prevention strategies tailored to individual pipeline attributes and operating conditions.
- Development of encroachment probability models based on one-call data trends and urban growth patterns.
- Development of a combined pipeline integrity and surveillance management system and the development of an overall framework for its implementation.
- Extension of the best practices of prevention technologies and procedures developed by the Texas Excavation Safety System, Inc. (TESS) for the Gulf of Mexico to offshore systems of the Pacific and Atlantic areas and should also be considered. See information at http://www.gulfsafe.com/.

11.3 Detection and Characterization

Mechanical damage is most often detected and characterized with ILI tools that identify pipe wall deformations (e.g., dents) and metal loss. Because mechanical damage can contain coating damage, residual stresses, plastic strains, cracks, and microstructural damage, technologies that can detect and characterize one or more of these features would be beneficial.

Several ILI vendors are developing and offering tools with multiple inspection technologies to detect and characterize other defect features. The principal aim is to develop reliable detection and characterization with discrimination and resolution of the key features that determine damage severity. At present, while dent depth and the overall dimensions of the damaged region may be measured satisfactorily, the capabilities relating to key secondary features are largely qualitative rather than quantitative.

As ILI technology improves, the threshold depth for damage detection is expected to diminish and the number of reported mechanical damage sites is expected to increase. ILI tools that reliably discriminate among plain dents, dents with secondary features, and dents that have largely re-rounded but still have substantial associated stress and strain fields will become more important. Reliable methods for discriminating and assessing the severity of re-rounded dents or shallow damage are becoming an important need.

In summary, the most important gaps with regard to the detection and characterization of mechanical damage are:

- Multi-function ILI technologies and procedures that accurately and reliably detect secondary mechanical damage features, with a focus on shallow damage defects. This includes quantification of secondary features.

- Methods of detecting and characterizing damage using aboveground methods. Mechanical damage can be detected indirectly using the methods that detect coating damage, but there is considerable uncertainty regarding the extent and severity of damage.
- Better methods for differentiating among re-rounding cracks, other cracks, and benign linear indications during in-the-ditch inspections. In addition, improvements in crack depth measurement, especially for cracks situated at the inside surface.
- Technology for detection and quantification of damage in non-piggable pipelines.

11.4 Assessment

As corroborated by current research and supported by input from many of the pipeline operators interviewed for this study of mechanical damage, there are a variety of needs associated with assessing mechanical damage reported by ILI. First, better methods are required to guide and prioritize decisions to excavate a given indication based on ILI data. Here, the analysis can be rudimentary, provided it yields reliable “go/no go” decisions.

Secondly, a need less commonly cited than the first, is the ability to conduct detailed assessments of damage severity where excavations are extremely difficult, dangerous, or expensive.

In addition, improved ILI methods are required to evaluate damage that poses a near-term threat to pipeline integrity and/or to determine how close the expected failure pressure is to the operating pressure. This type of assessment is needed to determine the immediacy of response (including any requirement for the operating pressure to be reduced prior to intervention).

Research is also required to develop better methods for assessing severity based on in-the-ditch measurements following an excavation. Some operators base their decision of whether to remediate mechanical damage on rigidly conservative criteria (e.g., automatically repairing any mechanical damage defect found to contain a gouge or linear indication). Others advocate the three-tiered approach based on the degree of risk. This approach consists of an initial screening of defect severity (Level 1), backed up by more accurate methods (Level 2) and, if appropriate, detailed Engineering Critical Analysis (Level 3). Current guidance already supports a three-tiered approach for the assessment of pipeline defects that may be unassociated with mechanical damage, such as metal loss. At present, most of the assessment methods for mechanical damage are based on depth alone (Level 1) or simple empirical formulae (Level 2).

Some operators express a desire to better understand how mechanical damage can worsen with time under the influence of pressure cycling. At present, the methods are simplistic, and the data demonstrate a high degree of scatter compared to experimental results. The development and validation of improved models for describing time-dependent and cycle-dependent behavior could be an essential prerequisite to determine the remaining life of the affected pipe segment and/or re-inspection interval for damage left uninvestigated in a pipeline.

Another important initiative for future research is the development of improved methods to assess mechanical damage that occurs in conjunction with pipeline welds - especially newer welds with good mechanical properties, such as corrosion resistance, toughness, etc. Preliminary estimates suggest that up to five percent of mechanical damage occurrences may be close enough to seam or girth welds for the failure pressure to be influenced by their interaction. While many operators consider mechanical damage near a weld to be an automatic cut out or repair, others would like the option of not repairing damage near, for example, modern electric resistance weld (ERW) seams.

Lastly, there is a need to better understand the conditions under which accelerated corrosion or stress corrosion cracking occurs. The extent to which the environment contributes to the problem of time-dependent or cycle-dependent damage is not well established, and an approach that accounts for the possible effects of the environment should be developed.

In summary, there are a number of important gaps in existing research for the assessment of the severity of mechanical damage. The most significant requirements to be addressed are as follows:

- Reliable methods for determining which ILI indications should be excavated first to further assess their severity and/or need for repair.
- More reliable methods of assessing defect severity from ILI data for those cases where excavations are difficult, dangerous, or expensive.
- Methods of determining whether a given ILI indication is a near-term threat to integrity and/or methods of assessing when and where pressure reductions are necessary.
- More robust, validated mechanics-based models for assessment of the severity and remaining life of mechanical damage, such as the establishment of a three-tiered approach to damage assessment similar to those already in place for other types of defects.
- Analysis methods for damage on or near welds, especially modern welds with good mechanical properties.
- Methods of predicting the remaining life of mechanical damage left uninvestigated via excavation after ILI or direct assessment.
- Methods to predict when and where accelerated corrosion and/or stress corrosion cracking may occur.
- Future research and development might lead to new technologies for detecting mechanical damage for non-piggable pipelines. This will require establishing analytical methods similar to those described in 1, 2, and 3 above.
- The creation of comprehensive databases that can be used to validate and/or develop the analytical methods described above would also be useful.

11.5 Mitigation / Repairs

The application of safe and efficient repair methods to ensure the long term integrity of a damaged pipeline is important. The most critical area for further development is the use of composite repair systems. Such systems are increasingly being considered for the repair of mechanical damage, although many operators restrict their use due to insufficient experience, or concerns about their ability to prevent damage during pressure cycling or even their resistance to future possible mechanical damage.

The two most important gaps related to mitigation and repairs are:

- The development of guidelines for the implementation of composite repairs, accounting for the different types and characteristics of mechanical damage, as well as the loading experienced by gas and liquids pipelines (i.e, defining a range of applications for the repair technique).
- Evaluation of the long-term effectiveness and reliability of general repair techniques for time-dependent threat management, including the establishment of performance-testing protocols.

11.6 Industry Interviews

The gaps described above were identified by the authors during the preparation of this report. In addition, the authors conducted interviews with members of the pipeline industry as part of this study, to further clarify their understanding of the gaps and associated research requirements. Pipeline operator interviews were structured to obtain candid input on current practices employed and recognized needs for mechanical damage prevention, detection/characterization, assessment, and mitigation/repair.

Operators identified the following as key gaps or areas in which future research should focus. Many of these gaps are identical in nature to those presented in the previous sections of this chapter:

- Stronger emphasis on enforcement related to the one-call system.
- Improved public awareness and/or more stringent regulations and enforcement, for controlling right-of-way activity and preventing mechanical damage.
- Shared understanding among pipeline operators and regulators as to those instances of mechanical damage that pose a valid threat to pipeline integrity.
- Increased interactions and discussions with contractors on planned excavations.
- Methods and protocols for data integration between ILI and one-call systems.
- Improved ILI technologies, such as combination tools, to better identify and characterize features associated with mechanical damage. Also, improved ILI technology for detecting cracks in dents.
- Effective method for in-the-ditch assessment (e.g. strain analysis) to govern the decision-making process for damage repairs.
- Advanced technologies that emphasize prevention rather than mitigation of mechanical damage.

11.7 General Issues

In addition to the gaps identified above, there are a number of other general issues and gaps that are not directly tied to prevention, detection/characterization, assessment, and mitigation/repair, or that are common to more than one of these areas. There are also gaps and issues that are common to other integrity threats. These include:

- **Consistent recording and collection of data –** Improvements in the consistency of recording of damage occurrences, including submission of data to DIRT, together with the associated pipeline attribute and operational circumstances are essential to the effective interpretation of incident databases. Consistent databases are required, related to the common set of factors or characteristics of mechanical damage, including those related to prevention, detection, assessment, and mitigation.
- **Data interpretation –** There is an ongoing need to collate and interpret data related to mechanical damage, and in particular, to establish appropriate ways of handling the extreme values that most often are associated with failures in service.
- **Information management processes –** Better methods to align and integrate operating pressure databases, GIS systems, and assessment software would permit more complete evaluation of factors that affect damage severity, including fatigue and other time-dependant degradation processes.
- **Alternative tools –** Alternative methods are required to detect and characterize mechanical damage where ILI cannot be employed.
- **Accommodation of uncertainties during damage assessment –** Methods to account for factors that vary significantly from case to case and that cannot be estimated or measured with certainty are needed. Emerging assessment tools may need to incorporate probabilistic and reliability-based methods to account for uncertainty in the input data and in the analytical assumptions. Such methods will provide valuable insight into how the individual sources of uncertainty contribute to defect severity and how to focus research efforts on the areas of greatest concern.

11.8 Summary and Key Findings

Based on information obtained from the published literature, proprietary reports, industry interviews, and industry experience surveys, the PHMSA Workshop on Mechanical Damage, and studies commissioned by PRCI, a number of outstanding issues and gaps concerning mechanical damage were identified. The following is a summary of the most important gaps:

- ***Prevention:***
  - Better one-call enforcement
  - Improved understanding of the effectiveness of different prevention methods
  - Better ways of enhancing public awareness

- ***Detection:***
  - Improved ability to intercept possible perpetrators before they inflict damage on the pipeline
  - For the four percent of the threat that is prior damage, improved ability of in-line inspection (ILI) technology to detect mechanical damage, including the ability to discriminate and characterize all critical features that determine damage severity
  - Methods of detection and characterization of mechanical damage on non-piggable pipelines

- ***Assessment:***
  - Improved ability to use ILI data in the decision to excavate / not excavate
  - Improved methods of determining the need for immediate action or pressure reduction
  - Multi-tiered analysis methodologies
  - Validated methods to assess the remaining life of pipelines that are impacted by mechanical damage

- ***Repairs:***
  - Guidelines on the selection and application of wet wrap composite repair systems I
  - Improved confidence in the long-term performance reliability of all repair systems

- ***General:***
  - Common definitions, improved information management systems, and databases related to mechanical damage

Finally, matters on gap analysis are generally determined by industry/government consensus-driven events, such as R&D forums. No attempt has made in this report to provide an analysis to determine what quantifiable safety benefits might be realized by closing the gaps, or to provide prioritization of future R&D efforts and resources.

11.9 References

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12 Summary

Mechanical damage from third-party intrusion remains a leading cause of significant pipeline incidents. Research and testing programs have led to an understanding of mechanical damage. Future R&D efforts must concentrate on prevention, since greater than ninety-five percent of the incidents and associated injuries and damages are associated with immediate failure, with few associated with delayed failure. However, these delayed failures have proven to be very newsworthy. Therefore, discovery and assessment methods should be likewise emphasized. In addition, many developments have addressed how to prevent mechanical damage, detect it, assess its severity, and repair and mitigate its effects. With such a broad base of prior work, it is not surprising that no single document compiles and reviews all topics in a way that is broadly accepted by all stakeholders and that can act as a benchmark for advancing the technologies. This report has attempted to fill that gap as a review and summary of research, development, and experience related to mechanical damage in natural gas and hazardous liquid steel pipelines, with particular focus on transmission pipelines. This chapter summarizes the major findings of the report.

12.1 Understanding Mechanical Damage in Pipelines

Mechanical damage introduced by various kinds of equipment or circumstances demonstrates a broad range of characteristics. The physical attributes of the damage itself vary greatly. As with any defect, the severity depends on the defect geometry, the properties of the pipe steel, and the stresses and loadings on the pipeline. Many factors related to how a mechanical damage defect was formed are typically unknown because the damaging event was not witnessed or reported.

12.1.1 Types and Characteristics of Damage

In this report, prior mechanical damage was broadly categorized in three types: dents, gouges, and combined dent/gouge defects. The term “dent” refers to changes in cross-sectional shape, along with associated plastic strains and deformations. Gouges refer to movement and/or removal of metal. Gouges typically appear as a localized change in wall thickness but may also contain damage to the pipeline steel’s microstructure, cracks, etc. Gouge and dent defects, where both forms of damage are present, are common.

Of particular importance in understanding mechanical damage is the potential for the pipe to re-round and spring-back after the damage has been inflicted. Re-rounding and spring-back implies the observed size and shape of a dent may not reflect the true severity of the damage. Two similarly shaped dents could be caused by different processes leading to different severities: a rock dent that has not re-rounded may be less severe than a dent due to an impact, after which re-rounding has occurred.

Other important factors related to mechanical damage severity include strain damage to the microstructure (which is not usually visible), the potential for the damaged area to flex, and the presence of cracks or other defects. These and other factors are the subject of continuing research and development.

12.1.2 Failure Statistics

Pipeline failure data have been collected by agencies in the United States, Canada, Europe, and elsewhere. Periodically, analyses have been used to identify trends and risk factors. The data demonstrate that immediate mechanical damage is a regular cause of pipeline failures. With the advent and widespread adoption of public awareness systems such as one-call systems, the number of mechanical damage incidents has decreased in recent years, but on occasion, serious accidents still occur.

Most mechanical damage failures and related injuries and fatalities are immediate rather than delayed. Immediate failures occur when the pipe is punctured, releasing its contents. Failures from prior damage that occur days, months, or years after the damage has been inflicted are much less common. The ratio of immediate mechanical damage incidents to those from other causes is comparable for liquid and gas transmission pipelines.

12.2 Prevention

Mechanical damage prevention is complicated because damage can be caused by numerous means. Pipeline operators, excavators, regulators, public safety officials, and the public recognize the importance of damage prevention and the need to address contributing factors.

There are a wide variety of prevention practices, ranging from planning and land use restrictions to surveillance and one-call programs. A common nationwide one-call telephone number (811) was launched in the United States in April 2007. The toll-free number connects individuals planning to excavate with appropriate local one-call centers and should eliminate multiple one-call numbers across the country. Since the announcement of the 811 number, many stakeholders have begun public campaigns to raise awareness.

Emerging technologies are also being developed. These include various encroachment monitoring systems to detect when unanticipated encroachment is occurring, tools for contact monitoring during excavation as well as obstacle detection devices mounted on excavating equipment, and others.

Lastly, these prevention activities are supplemented by government and industry initiatives to reduce the potential for damage due to excavating and similar equipment. Two major initiatives are the Common Ground Alliance's (CGA) best practices documents and its Damage Information Reporting Tool (DIRT).

Prevention is widely considered the most effective means of reducing damage to human life, property, and the environment from mechanical damage. Critical prevention practices include the use of the one-call systems, implementation of public awareness initiatives, and enforcement of safe excavation requirements and procedures.

12.3 Detection, Identification, and Characterization

Mechanical damage occurs despite the prevention practices summarized above. Latent damage can be detected in a variety of ways, such as by in-line inspection (ILI), aboveground surveys, and direct examinations. None of these methods detects, identifies, and characterizes all defects under all conditions. For example, many systems do not differentiate between prior mechanical damage and metal loss due to corrosion. The most commonly used method of detecting mechanical damage is ILI.

Several categories of ILI equipment are available, but most tools were not developed principally to detect mechanical damage. As a result, their effectiveness with respect to mechanical damage is less than that for other defects such as corrosion, weld defects, or stress corrosion cracking. Capabilities, limitations, and reliabilities of different ILI technologies, and how pipeline companies generally view them, are summarized below:

- Caliper or geometry tools are considered reliable at detecting and identifying dents, provided the dents exceed a threshold depth. Caliper and geometry tools are not used for metal loss, gouges, metallurgical damage, and cracks.

- Magnetic Flux Leakage (MFL) tools are considered reliable at detecting metal loss and some dents, but they are not widely seen as capable of reliably identifying and characterizing metal loss in dents. This is especially true for damage that is highly localized and abrupt. Some MFL sensor systems are being developed to detect and identify microstructural damage, but experience is limited. MFL tools have sometimes detected cracks, but the ability to do so for mechanical damage is largely suspect.
- Ultrasonic metal-loss tools are considered reliable at detecting, identifying, and characterizing dents and metal loss associated with gouges, but not to differentiate gouges from other forms of metal loss. Their ability to detect and characterize metal loss in gouges is not well defined.
- Ultrasonic crack-detection tools have detected and characterized anomalies in welds and the pipe body, but they are not generally considered reliable at detecting or characterizing cracks in mechanical damage.

Aboveground ECDA surveys, such as voltage gradient surveys, are considered reliable at detecting coating damage, and they have detected mechanical damage. These techniques are rarely used to detect mechanical damage because they cannot differentiate coating holidays from mechanical damage. On occasion, the surveys integrated with correlated historical observations are used to detect damage at locations such as where prior right-of-way encroachment is identified by surveillance. They can not be used to determine the severity of mechanical damage.

In-the-ditch inspections and measurements are considered most reliable at identifying and providing data on mechanical damage, but all of the commonly used techniques have limitations. In-the-ditch techniques are regularly used to obtain detailed information on the geometry of mechanical damage and surrounding wall thickness. For other characteristics, magnetic particle, ultrasonic wall thickness, and ultrasonic shear wave inspections are also used, often in conjunction with grinding. Less commonly, etching/in-situ metallography, and portable (field) hardness testing are used. However, in-the-ditch characterization methods are not yet available in a comprehensive guideline to provide unified industry guidance, particularly on measurement uncertainties that affect the quality of the defect assessment.

For crack sizing, angle beam ultrasonics is used, but the results are not broadly accepted as reliable for cracks in mechanical damage. Selective grinding combined with magnetic particle inspection is used by many operators and is considered accurate. Other potentially useful technologies include time-of-flight diffraction, eddy current testing, and laser UT crack depth measurement.

12.4 Assessment

Numerous programs have attempted to develop usable methods of determining the severity of the damage. Each method has limitations and strengths. Some were developed to determine whether a given impact scenario will lead to a puncture, while others address factors such as re-rounding, local stress concentrations, and load-deflection behavior. The reliability of these assessment methods varies, and their use requires an understanding and familiarity with their development.

12.4.1 Assessment Models

Assessment models can be categorized as basic, intermediate, and advanced. Most available basic models are empirical or approximations extrapolated from tests or experience on in-service pipelines. These models consider simple damage only, such as smooth dents stress risers. They generally provide accept/reject criteria based on pipe properties, defect geometry, and internal pressure and are limited to pressure, strength, and fatigue.

Intermediate models add mechanics-derived formulations to improve failure predictions. These models incorporate understandings of fundamental processes of deformation, crack formation and growth, and they typically consider failure due to plastic instability or fracture. These models were developed to reduce the empiricism of basic analyses. They address different limit states, such as maximum allowable strain values.

Advanced models are based on mechanics principles and use test data and experience for calibration and to enhance confidence in the predictions. These models generally incorporate understandings of one or more degradation mechanisms, such as stable tearing. Often, their use requires detailed information on material properties and loading, during and after the damage is incurred.

Finally, a number of models provide insight into one or more aspects of mechanical damage behavior. They may or may not specifically address failure. Instead, they may have been developed to more fully understand factors such as the load/deformation response during denting and rerounding, stress and strain distributions, stress concentrations, etc.

12.4.2 Use of Mechanical Damage Models

Mechanical damage assessment models are not as simple or straightforward as those for corrosion. In addition, and in some cases, no amount of analysis can demonstrate that damage is acceptable due to inherent uncertainties. These difficulties must be considered.

Current industry practice is usually restricted to basic assessment models and simple acceptance/rejection criteria. Intermediate assessments are mostly used on a case-by-case basis, while more advanced models are mostly used for very unique situations and/or to gain the deep understanding needed to develop assessment models for the future. Observations based on industry experience, research and development, and published literature includes:

- Dent depth criteria of six to 10 percent are commonly used for screening the severity of smooth dents, whether constrained or unconstrained. Dent strain calculations and criteria are mostly restricted to use with in-the-ditch measurements. Resolution and measurement errors should be considered in an evaluation, and they are not typically used where there is cyclic loading, significant re-rounding, cracking, and changes in microstructure.
- For gouges that are axially oriented, fracture-mechanics models are sometimes used to predict burst pressure. These models generally show good correlation with measured burst pressures. The correlations are less for gouges that are not axially oriented.
- For dents with gouges, acceptable depth and strain limits of two percent to four percent have been used for dents with corrosion or that cross good quality welds. These acceptance criteria are based on limited experimental results. Burst pressure predictions for dent/gouge defects typically show a high degree of scatter, and must incorporate large safety factors to compensate for "model uncertainty." The same is true for fatigue data and remaining life predictions. There are not widely used.

12.5 Mitigation and Repair

Mitigation refers to corrective actions taken by a pipeline operator after learning mechanical damage is or may be present. The most common mitigation activity is a pressure reduction, either immediately or for excavation. Less commonly, pipelines are shut down. The perceived need for mitigation is based on regulatory requirements and the operator's understanding of its pipeline system.

Several repair methods are available for pipelines with mechanical damage, including sleeves, recoating, and cutouts. For significant damage, operators generally use Type A (non-pressure-containing) or B (pressure-containing) steel sleeves, although composite and other repairs are also used. Many operators use simple criteria to select the repair type; for example, use of a pressure-containing sleeve for any dent with a gouge, linear indication, or stress riser.

12.6 Industry Experience

To gain additional insights, interviews were conducted with pipeline operators and those who are "in the trenches." Representatives from 10 pipeline operators – representing a diverse cross section of industry professionals in the United States, Canada, and Europe – were interviewed. These interviews covered both gas and liquid transmission and gas distribution pipelines (the latter were included for comparison purposes). Interviews also encompassed operators of large- and small-diameter transmission systems and smaller-diameter distribution pipelines, and addressed both steel and plastic pipe systems. Geographic locations included remote and rugged terrain, rural areas, and constrained urban environments.

The majority of the operators interviewed acknowledged that mechanical damage is a serious and ongoing threat to the integrity of their systems and, consequently, to safety and health. Some operators reported that corrosion and/or stress corrosion cracking are more significant threats to their systems and should receive more attention. Many operators identified rock damage as the dominant form of mechanical damage. Those that reported human intervention as the primary cause typically had far fewer instances of damage.

Prevention is seen as a critically important focus. Increased enforcement of the existing laws for one-call notification and the imposition of stricter penalties for violators are regarded as integral to reducing mechanical damage. Increasing public awareness through communication is likewise considered essential to reduce pipeline strikes by the public.

In addition to prevention, operators consider prior damage detection, characterization, and mitigation as areas for improvement. Nearly all of the operators use ILI, but many considered the tools unreliable at differentiating benign from threatening damage. Some operators call for improved in-the-ditch assessment methods to differentiate cracks from other linear indications.

Pressure reductions are common when significant damage is suspected and for excavations. Type A sleeves are most commonly used to repair plain dents, while dents with gouges or other defects are most often repaired with Type B sleeves. Cut-outs are performed on a case by case basis.

12.7 Regulatory and Other Recommended Practices

U.S. Department of Transportation (DOT) regulations require that hazardous liquid and natural gas transmission pipeline operators identify and address integrity threats to their systems, including mechanical damage. Pipeline operators are also required to regularly assess their integrity management, mitigation, and prevention programs for adequacy. DOT regulations provide simple criteria for evaluating and determining the need to remediate dents, based on dent depth, the presence of secondary features, and whether the damage is in a high-consequence area.

Legislation mandating the use of a common nationwide one-call telephone number (811) was implemented in April 2007. The 811 number connects individuals planning to excavate with appropriate local one-call centers and should eliminate the confusion of multiple one-call numbers across the country. Other government agencies, such as the Occupational Safety and Health Administration (OSHA) also provide rules and regulations aimed at mechanical damage. These rules and regulations typically address excavation, one-call notifications, and marking.

Various international government and industry organizations also issue regulations and recommended practices related to mechanical damage. For example, in Canada, the National Energy Board (NEB) is responsible for promoting safe construction and operation of nationally regulated pipelines, while individual provinces typically fall under that province's regulatory jurisdiction. Similar bodies and regulations exist worldwide.

While there are differences between international and U.S. regulations, their intent is always the same – to reduce the likelihood and consequences of mechanical damage failures. Differences relate in the emphasis placed on, for example, prevention and response versus detection. International industry guidelines and recommended practices are similar to those used in the United States. Most industry guidelines and recommended practices are widely shared, and many are based on documents originally prepared in the United States with direct input from international colleagues.

12.8 Research Gap Analysis

Reviews of published literature, proprietary reports, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Workshop on Mechanical Damage, and studies commissioned by PRCI and others were conducted to identify issues and gaps concerning mechanical damage. Key gaps that have been identified for each of the sections are summarized as follows:

- Prevention: Better one-call enforcement, improved communications, an improved understanding of the effectiveness of different prevention methods, and better ways of enhancing public awareness.
- Detection, Identification, and Characterization: Improved ability of ILI technology to detect prior mechanical damage, including the ability to discriminate and characterize all critical features that determine damage severity; methods for detection and characterization of mechanical damage on non-piggable pipelines; and the ability to quantify measurement uncertainty for both ILI and in-the-ditch methods in light of these uncertainties on defect assessment results.
- Assessment: Improved ability to use ILI data in the decision to excavate or not excavate, improved methods of determining the need for immediate action or pressure reduction, multilevel analysis methodologies to address activities ranging from initial screening to detailed engineering critical assessment, and validated methods to assess the remaining life of pipelines that are impacted by mechanical damage.
- Mitigation/Repairs: Guidelines on the selection and application of wet wrap composite repair systems, and improved confidence in the long-term performance reliability of all repair systems.
- General: Common definitions, improved information management systems, and databases related to mechanical damage.