NACE INTERNATIONAL

Leaders in Corrosion Control Technology℠

PIPELINE CORROSION INTEGRITY MANAGEMENT

JANUARY 2011

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Acknowledgements

The time and expertise of a many members of NACE International have gone into the development of this course. Their dedication and efforts are greatly appreciated by the authors and by those who have assisted in making this work possible.

The scope, desired learning outcomes and performance criteria of this course were developed by the Pipeline Corrosion Integrity Management Task Group under the auspices of the NACE Education Administrative Committee in cooperation with the NACE Certification Administrative Committee. It is the intention of this task group to continue toward development of additional NACE courses on integrity management.

On behalf of NACE, we would like to thank the task group for its work. Their efforts were extraordinary and their goal was in the best interest of public service — to develop and provide a much needed training program that would help improve corrosion control efforts industry-wide. We also wish to thank their employers for being generously supportive of the substantial work and personal time that the members dedicated to this program.

This group of NACE members also worked closely with the contracted course developers from Corrpro Companies, Inc. including lead developer Olagoke (Goke) Olabisi, Mike Baezner, David Kroon, Dale Lindemuth, Roy Martinez, Marvin Miller, and Larry Rankin.

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PIPELINE CORROSION INTEGRITY MANAGEMENT (PCIM) PROGRAM OVERVIEW

NACE is expanding its curriculum to include new programs focused on pipeline corrosion integrity. Current regulatory requirements and industry need for training in this area make this program a priority for NACE Education & Training. The program, which has two tracks–a field track and an engineering track, emphasizes technology, industry standards, regulations and decision-making directly related to pipeline corrosion integrity management—finding corrosion and repairing it.

PCIM Level 1

PCIM Level will focus on remediation technology and field techniques for carrying out integrity assessments. The goal is to prepare an individual to:

- accurately collect data for used for the evaluation and monitoring of a pipeline corrosion integrity plan.
- recognize pipeline anomalies.
- make recommendations for resolving technical issues "in the ditch".
- evaluate a pipeline in-service using ECDA and ICDA methods and techniques.
- recognize problems "in the ditch" and be able to collect the data necessary for further engineering evaluation.

PCIM Level 2

PCIM Level 2 will focus on the implementation and management of an integrity program for a pipeline system. The emphasis at this level is on integrity verification and maintenance optimization. The goal is that an individual completing these courses should be capable of interpreting integrity related data, performing an overall integrity assessment on a pipeline system, calculating and quantifying risk, and making recommendations to company management on risk management issues.

Welcome to the Pipeline Corrosion Integrity Management Course

Who Should Attend

The ***Pipeline Corrosion Integrity Management (PCIM) Course*** is intended to serve as the key engineering training track for the "PCIM Engineer" who is expected to focus on the implementation and management of an integrity program for a pipeline system. The goal is that an individual completing the PCIM course should be capable of interpreting integrity related data, performing an overall integrity assessment on a pipeline system, calculating and quantifying risk, and making recommendations to company management on risk management issues. The course provides a comprehensive up-to-date coverage of the various aspects of time-dependent deterioration threats to liquid and gas pipeline systems.

Prerequisites

8 years pipeline work experience
OR
4 years pipeline work experience

AND 4-year degree in physical science or engineering

Or NACE Specialist certification

- *Recommended for course attendance*

Length

The course will begin on Monday through Friday 8:00 am to 5:00 pm.

Quizzes and Examinations

There will be quizzes distributed during the week and reviewed in class by the instructors.

The final written exam, which will be given on Friday, will consist of 100 multiple-choice questions. The examination is open book and students may bring reference materials and notes into the examination room.

A score of 70% or greater is required for successful completion of the course. All questions are from the concepts discussed in this training manual.

Non-communicating, battery-operated, silent, non-printing calculators, including calculators with alphanumeric keypads, <u>are permitted</u> for use during the examination. Calculating and computing devices having a QWERTY keypad arrangement similar to a typewriter or keyboard <u>are not permitted</u>. Such devices include but are not limited to palmtop, laptop, handheld, and desktop computers, calculators, databanks, data collectors, and organizers. Also <u>excluded</u> for use during the examination are communication devices such as pagers and cell phones along with cameras and recorders.

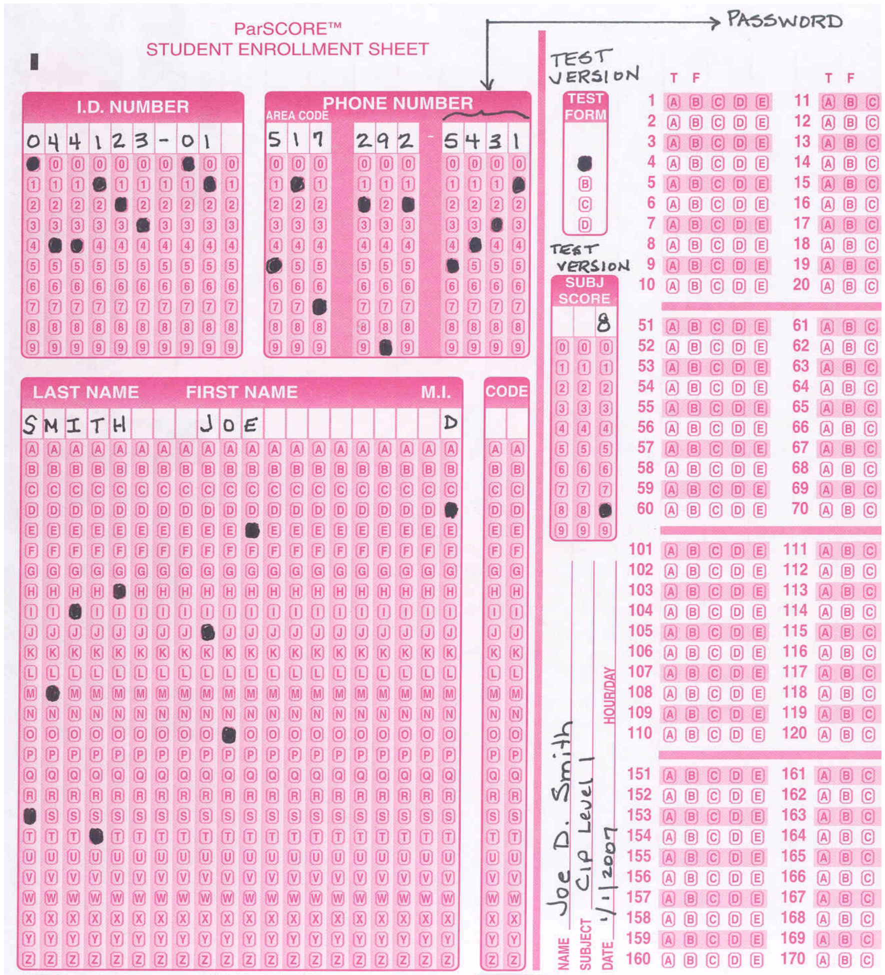
Instructions for Completing the ParSCORE^{TM} Student Enrollment Sheet/Score Sheet

1. Use a Number 2 (or dark lead) pencil.

2. Fill in all of the following information and the corresponding bubbles for each category:

√ ID Number: Student ID, NACE ID or Temporary ID provided
√ PHONE: Your phone number. The last four digits of this number will be your password for accessing your grades on-line. (for Privacy issues, you may choose a different four-digit number in this space)
√ LAST NAME:Your last name (surname)
√ FIRST NAME: Your first name (given name)
√ M.I.: Middle initial (if applicable)
√ TEST FORM: This is the version of the exam you are taking
√ SUBJ SCORE: This is the version of the exam you are taking
√ NAME: _______________ (fill in your entire name)
√ SUBJECT: ____________ (fill in the type of exam you are taking, e.g., CIP Level 1)
√ DATE: _______________ (date you are taking exam)

3. The next section of the form (1 to 200) is for the answers to your exam questions.
   •All answers MUST be bubbled in on the ParSCORETM Score Sheet. Answers recorded on the actual exam will NOT be counted.
   •If changing an answer on the ParSCORETM sheet, be sure to erase completely.
   •Bubble only one answer per question and do not fill in more answers than the exam contains.



EXAMINATION RESULTS POLICY AND PROCEDURES

It is NACE policy to not disclose student grades via the telephone, e-mail, or fax. Students will receive a grade letter, by regular mail or through a company representative, in approximately 6 to 8 weeks after the completion of the course. However, in most cases, within 7 to 10 business days following receipt of exams at NACE Headquarters, students may access their grades via the NACE Web site.

WEB Instructions for accessing student grades on-line:

√ Go to: **www.nace.org**

√ Choose: **Education**
Grades
Access Scores Online

√ Find your **Course ID Number** (Example 07C44222 or 42407002) in the drop down menu.
√ Type in your **Student ID or Temporary Student ID** (Example 123456 or 4240700217)*.
√ Type in your **4-digit Password** (the last four digits of the telephone number entered on your Scantron exam form)
√ Click on **Search**

Use the spaces provided below to document your access information:

STUDENT ID__________________	**COURSE CODE**__________________
PASSWORD (Only Four Digits) ___________________	

*Note that the Student ID number for NACE members will be the same as their NACE membership number unless a Temporary Student ID number is issued at the course. For those who register through NACE Headquarters, the Student ID will appear on their course confirmation form, student roster provided to the instructor, and/or students' name badges.

For In-House, Licensee, and Section-Registered courses, a Temporary ID number will be assigned at the course for the purposes of accessing scores online only.

For In-House courses, this information may not be posted until payment has been received from the hosting company.

Information regarding the current shipment status of grade letters is available upon the web upon completion of the course. Processing begins at the receipt of the paperwork at NACE headquarters. When the letters for the course are being processed, the "Status" column will indicate "Processing". Once the letters are mailed, the status will be updated to say "Mailed" and the date mailed will be entered in the last column. Courses are listed in date order. Grade letter shipment status can be found at the following link:
http://web.nace.org/Departments/Education/Grades/GradeStatus.aspx

If you have not received your grade letter within 2-3 weeks after the posted "Mailed date" (6 weeks for International locations), or if you have trouble accessing your scores on-line, you may contact us at **GradeQuestions@nace.org**

DAILY SCHEDULE	
DAY ONE	
Chapter 1	Introduction to Pipeline Integrity
	Overview of Impact of Corrosion on Pipelines
	Overview of Corrosion Control Methods
	Other Threats to Pipeline Integrity (non-corrosion related)
Chapter 2	Managing corrosion
	Corrosion Detection Methods
	Corrosion Mediation Methods
	Corrosion Remediation Methods
Quiz 1 (Chapters 1 & 2)	
Chapter 3	Regulations: Overview of 49 CFR 192: Natural Gas
	Regulations: Overview of 49 CFR 195: Hazardous Liquid
Chapter 4	Standards: Managing System Integrity (ILI, Hydrostatic Testing)
	Standards: Direct Assessment Processes (ECDA, SCCDA, ICDA)
DAY TWO	
Chapter 5	Data Collection and Validation
	Data Integration and Interpretation
Chapter 6	Risk Assessment
	Risk Quantification and Minimization Through Corrosion Control
Quiz 2 (Chapters 3-6)	
Chapter 7	Integrity Verification/Assessment
	Integrity Verification/Assessment Methods

DAILY SCHEDULE	
DAY THREE	
Chapter 8	Technical Challenges: Pipeline Manufacturing & Construction
	Technical Challenges: Pipeline Operation & Failure Sources
Chapter 9	Remediation Activity and Repair Methods
	Repair Methods and Protocol
Chapter 10	Assessment Interval: Remaining Strength
	Assessment Interval: Corrosion Growth Rates
Quiz 3 (Chapters 7-10)	
Chapter 11	Post Integrity Assessment Risk Analysis
DAY FOUR	
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	Change Management: Communication & Quality Control Plans
Chapter 13	Management Perspectives and Case Studies
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Preface

Pipeline integrity management embodies an error-free, leak-free, spill-free, and incident-free operation of a pipeline system, onshore and/or offshore, with no ill effects on health, safety, environment (HSE) and the economy. It encompasses (1) developing an integrity management program consisting of 5 key plans; (2) assessing pipeline threats; (3) carrying out mitigation, detection and prevention of all forms of pipeline defects; and (4) monitoring and review.

This ***Pipeline Corrosion Integrity Management (PCIM) Course*** underscores these. It is intended to serve as the key engineering training track for "PCIM Engineer" who is expected to focus on the implementation and management of an integrity program for a pipeline system. The goal is that an individual completing the PCIM course should be capable of interpreting integrity related data, performing an overall integrity assessment on a pipeline system, calculating and quantifying risk, and making recommendations to company management on risk management issues. The course provides comprehensive up-to-date coverage of the various aspects of time-dependent deterioration threats to liquid and gas pipeline systems.

The PCIM course is composed of thirteen chapters prepared by several corrosion experts. Each chapter was edited, reviewed, and revised by another coterie of corrosion experts. The chapters were grouped in a pragmatic approach that systematically leads the students from the simple to the more complex issues. The final outcome represents a cohesive treatment that illustrates the phenomenal progress made so far in pipeline corrosion integrity management and the still evolving global environmental protection security issues.

Chapter 1, ***Introduction to Pipeline Integrity***, provides some basic definitions and an overview of corrosion's impact on pipelines. The chapter was designed to satisfy the needs of a busy manager and engineer by providing a bird's eye view of the essential tenets of pipeline corrosion integrity management. This chapter also covers the benefits of pipeline integrity programs in enhancing public safety, improving goodwill and investor relations, reducing liabilities (and perhaps insurance premiums), providing environmental protection, enhancing system reliability and extending the life of company assets.

Chapter 2, ***Managing Corrosion***, provides a comprehensive identification of eight forms of corrosion, discusses time-dependent threats to pipeline integrity and identifies the tools used for corrosion detection methods. Together, Chapters 1 and 2 illustrate the key corrosion control methods as well as their synergistic effects.

Chapter 3, ***Regulations***, addresses the pipeline regulations of the United States' government agencies associated with pipeline operations. This chapter presents an overview of 49 CFR Parts 192 and 195, particularly the sections dealing with integrity requirements and regulatory interpretations.

Chapter 4, ***Standards***, is devoted to the understanding of the purpose of standards and guidelines that relate to PCIM. Because of the continuing evolution of pipeline related technologies, standards and guidelines are continuously modified to keep abreast of advancing technologies as well as the changing government regulations and industry needs. **NOTE:** NACE International publishes three classes of standards: standard practices, standard material requirements, and standard test methods. Until June 23, 2006, NACE published *standard recommended practices*, but the designation of this type of standard was changed to simply *standard practice*. New standards published after that date will carry the new designation (SP), and existing standards will be changed as they are revised or reaffirmed. **The most recent version should be used.**

Chapter 5, ***Data Collection, Verification and Integration***, addresses the elements of the integrity program where data integration is performed, the types of integrity information that are to be integrated for analysis, expected results from data integration, methods for integrating information, and qualifications of personnel that perform data integration.

Chapter 6, ***Risk Assessment***, addresses the history and probability of pipeline failures, the process of consequence analysis, the quantification of risk, relative and absolute. It also includes a discussion about the issues of risk and risk assessment methodology. It outlines the distinction between prescriptive and performance-based integrity processes with particular attention to the peculiarity of their data sources and methods of analysis.

Chapter 7, ***Integrity Verification/Assessment***, articulates the need for pipeline operators to determine the adequacy of their pipelines to operate at the originally established allowable pressure by performing necessary inspections to identify time-dependent defects that could prove detrimental to the continued safe operation of the pipeline system.

Chapter 8, ***Technical Challenges to Pipeline Integrity***, discusses the background information and the necessary methodology of addressing pipeline integrity technical challenges faced by the pipeline industry as a whole.

Chapter 9, ***Remediation Activity/Repair Methods***, will look at the different types of remediation activities available in pipeline integrity assessment.

Chapter 10, ***Inspection and Assessment Intervals***, explores the key factors in establishing appropriate intervals between inspections, such as the remaining life, the defect types and sizes detectable by the inspection method used, the stress levels, the defect growth rates, and the effectiveness of actions taken to correct chronic time-dependent problems.

Chapter 11, ***Post Integrity Assessment Risk Analysis***, emphasizes the need for a post-integrity-assessment risk analysis when the management of change process dictates.

Chapter 12, ***Integrity Management Plan***, addresses the reasoning and rationale for comprehensive documentation requirements for Management of Change (MOC) and Quality Control.

Chapter 13, ***Management Perspectives***, discusses the management responsibility and potential civil and criminal indictments that could result from management inattention to the virtues of PCIM. It also illustrates how the learnings from the PCIM course could be put to practice through familiarity with relevant case studies.

Chapter 1: Introduction to Pipeline Integrity

After completing this chapter, students should be able to:

- Define pipeline integrity.
- Understand the impact of corrosion on pipeline integrity.
- Enumerate the ASME B31.8S list of 21 threats, nine categories of failure types, and three time-related defect types of concern for integrity management.
- Be able to articulate the benefits of Pipeline Integrity Programs, i.e., enhancing public safety, improving goodwill and investor relations, reducing liabilities (and perhaps insurance premiums), providing environmental protection, enhancing system reliability and extending the life of company assets.
- Know that there are many threats to the integrity of a pipeline system, and that understanding these threats is paramount to develop and implement an effective pipeline integrity management program.
- Understand the components of a Pipeline Integrity Program: an Integrity Management Plan, a Performance Plan, a Communications Plan, a Management of Change Plan, and a Quality Control Plan.
- Be able to help develop company specific goals and objectives for the Pipeline Integrity Management Program.

1.1 Pipeline Integrity

1.1.1 Definition

Pipeline includes all parts of those physical facilities through which oil and gas move in transportation, including pipe, valves, and other appurtenances attached to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Pipeline integrity is the state of a pipeline with respect to public safety, environmental protection, and operational reliability. It implies that a pipeline system is sound and capable of safely performing the tasks for which it was designed and is compliant with the applicable regulations and standards governing design, operation, and maintenance. That is, it embodies an error-free, leak-free, spill-free, and incident-free operation of a pipeline system, onshore and/or offshore, with no ill effects on health, safety, environment and the economy. Pipeline integrity management encompasses (1) developing a program/plan; (2) assessing threats; (3) carrying out mitigation, detection and prevention of all forms of pipeline defects; and (4) monitoring and review.

According to ASME B31.8S, there are 21 threats, nine categories of failure types, and three time-related defect types that could compromise the integrity of a natural gas pipeline. The nine categories of failure types are as follows:

- Internal corrosion caused by produced fluids and gases
- External corrosion caused by exposure to groundwater, seawater, salt spray and weathering
- Stress corrosion cracking
- Manufacturing and related defects
- Construction and related defects
- Equipment and related defects
- Third-party inflicted damage
- Incorrect operations and procedures
- Weather-related, earth-related and other outside forces

API 1160 lists similar threats under the categories of metal loss and construction/third-party damage. Corrosion is one of the most important problems and it constitutes the first three threats to liquid and gas pipeline systems. Corrosion is the root cause of about 30% of the reported cases of hazardous liquid and gas transmission incidents. Hence, pipeline corrosion integrity management is a significant subset of the overall pipeline integrity management process.

1.2 Overview of Impact of Corrosion on Pipelines

NACE defines corrosion simply as the deterioration of material, usually a metal, due to reaction with its environment. Generally, corrosion could be detected using one or more of the methods described in Chapter 2. According to ASME B31.8S, three significant pipeline threats are posed by internal corrosion, external corrosion, and stress corrosion cracking. Corrosion is the most common "in-service" cause of pipeline failure and the cause of 6.4% of "loss of containment" failures of hazardous materials. When pipeline integrity is compromised by corrosion, the probability of potentially deleterious impact on health, safety, environment, and the economy is high.

The energy released when a metal converts to corrosion products is the driving force for its corrosion. Corrosion occurs naturally, and cannot be stopped completely, it can only be controlled. Pipeline corrosion is influenced by internal corrosion factors, external corrosion factors, and stress corrosion cracking factors. Controlling pipeline corrosion involves controlling such factors as oil field fluid conductivity, soil resistivity, electrolytes, pH, dissolved gases, intensity of microbiological activities, temperature, pressure, fluid mechanics, etc. For example, most oil wells do not have internal corrosion problems until water is produced. Similarly, pipelines buried in bone-dry soil suffer little or no corrosion until water from whatever source unleashes the corrosive power of the variety of mineral matter in soil. Pipeline stress corrosion cracking will not occur in the absence of stress and a corresponding hostile environment.

The compilation of corrosion data and the development of a usable corrosion database are crucial to any corrosion control program. This includes the following data:

- materials property
- protective coatings
- cathodic protection
- electrical interference
- environmental control

- failure analysis
- corrosion
- inspection
- monitoring, etc.

Corrosion increases the likelihood of accidents, causes loss of production and increases maintenance and operating costs of pipelines. The impact of corrosion includes consideration of the increased cost of mitigation, detection and prevention of pipeline defects. NACE has found the total annual estimated direct cost of corrosion in the U.S. to be a staggering $276 billion — approximately 3.1% of the nation's Gross Domestic Product (GDP).(1) This is only for "direct cost" which accounts for owner/operator costs and does not include the "indirect costs" to the user or the public. Pie Diagram Illustrating Relative Contributions to Direct Costs of Corrosion (Figure 1.1) shows that treatment chemicals represent more than 60% of the direct cost of internal and external corrosion control.

Another independent estimate of the total annual cost of corrosion in the US oil and gas industry is about $1.372 billion with a breakdown as follows (where OPEX is operating expenditure and CAPEX is capital expenditure):

- Surface and offshore facilities (OPEX) $589 million
- Downhole facilities (OPEX) $463 million
- Downhole and offshore facilities (CAPEX) $320 million

Although significant, corrosion control cost is exceedingly low compared to pipeline replacement cost. With an estimated pipeline construction cost of $694.100 per km ($1,117,000 per mile), it would cost $541 billion to replace the U.S. transmission pipeline infrastructure of 778,900 km (484,000 miles).

(1) Excerpt from the July 2002 MP Supplement— Corrosion Costs and Preventive Strategies in the United States

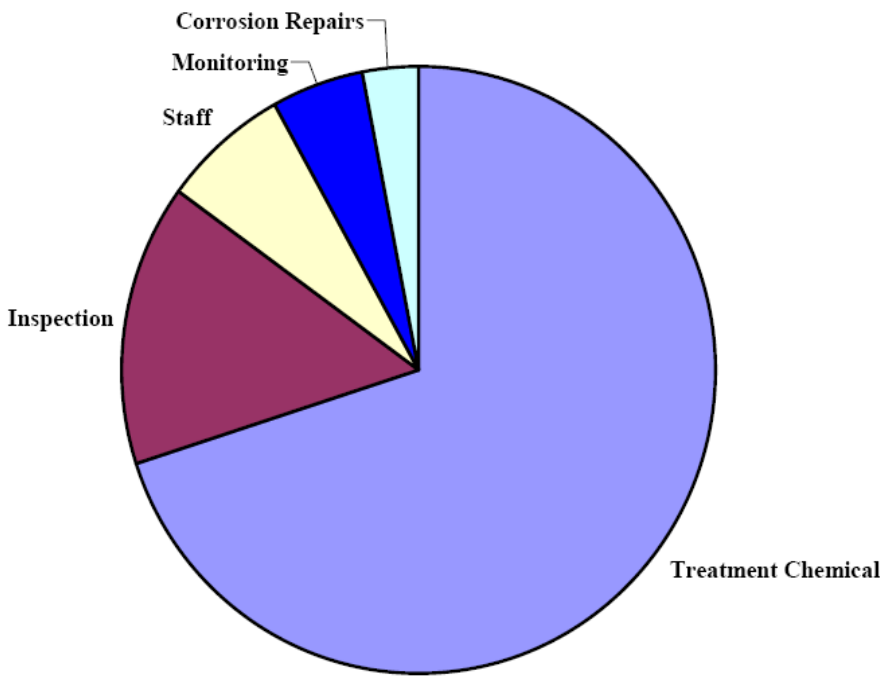


Figure 1.1 Pie Diagram Illustrating Relative Contributions to Direct Cost of Corrosion

When pipeline integrity is compromised, the probability of leakage becomes high. Oil or gas leakage has a potentially deleterious impact on health, safety, environment, and the economy. It is the recognition of the societal impact that has significantly elevated focus on pipeline integrity. This is perhaps a redeeming feature of corrosion's impact on pipeline integrity; health, safety and environmental (HSE) concerns which now drive government regulations globally.

For example, the U.S. Department of Justice has established the pipeline industry as the focus of increased environmental protection security supported by new laws providing powerful new prosecution tools to go after offenders. The U.S. Government now holds individual personnel—including non-management technical personnel—criminally responsible for accidents arising from poor pipeline operations. Criminal indictments, felony convictions, fines and civil penalties cost pipeline companies millions of dollars following any reportable pipeline leakage. Even if a corporation is charged in the event of a failure resulting in a breach of public safety, corporate executives and technical personnel will not necessarily escape prosecution.

The obstruction of justice provision of the U.S. Sarbanes-Oxley Act which passed in July 2002 has dramatically expanded the scope covered by U.S. federal criminal law. In environmental criminal cases (i.e., pipeline spills), prosecutors could include charges for false statements and obstruction of justice.

1.3 Other Threats to Pipeline Integrity (non-corrosion related)

According to ASME B31.8S, there are 21 threats, nine categories of failure types, and three time-related defect types that could compromise the integrity of a pipeline. The six non-corrosion categories of failure types are as follows:

- Manufacturing and related defects
- Construction and related defects
- Equipment and related defects
- Third-party inflicted damage
- Incorrect operations and procedures
- Weather-related, earth-related and other outside forces

These are further classified into stable and time-independent threats that, in principle, constitute the other two subsets of the overall pipeline integrity management process given as follows:

Stable defects type

1. Manufacturing related threats
   a) defective pipe seam
   b) defective pipe
2. Welding/fabrication related (construction) threats
   a) defective pipe girth weld
   b) defective fabrication weld
   c) wrinkle bend or buckle
   d) stripped threads/broken pipe/coupling failure
3. Equipment threats

a) gasket O-ring failure
b) control/relief equipment malfunction
c) seal/pump packing failure
d) miscellaneous

Time-Independent defects type

4. Third-party/mechanical damage threats
   a) damage inflicted by first, second, or third parties (instantaneous/immediate failure)
   b) previously damaged pipe (delayed failure mode)
   c) vandalism
5. Incorrect operational procedure threats
6. Weather-related and outside force threats
   a) cold weather
   b) lightning
   c) heavy rains or floods
   d) earth movements

1.3.1 Pressure Testing

To assure overall pipeline integrity and account for all possible anomalies, in-line inspection (ILI) tools and hydrostatic pressure testing are the key inspection methods that cover all the 21 threats, nine categories of failure types, and three time-related defect types. The schematic prescriptive integrity management plans for the six non-corrosion related categories of failure types are presented in Prescriptive Integrity Management Plan, Manufacturing Threat to Prescriptive Integrity Management Plan, Weather-related and Outside Force Threat (Figure 1.2 to Figure 1.5).

1.3.1.1 In-Line Inspection (ILI) Tools

The key advantages of ILI tools are:

- The ability to obtain accurate data for identifying and sizing of defects resulting from a number of different threats
- Applicability to long sections of pipeline
- The ability to retrieve and compare previously logged data for corrosion trending

- The transferability of data to geographic information systems (GIS)
- The non-destructive nature of the tools

Table 2.8 of Chapter 2 presents the inspection purposes, anomaly types, and ILI Tools to detect all the 21 threats to pipeline integrity.

1.3.1.2 Hydrostatic Testing

The key considerations of hydrostatic testing are:

- The pipeline must be taken out of service
- Only the critical flaws leading to failure at the time of testing are identified; sub-critical flaws are not identified
- A large volume of water must be used and disposed of in accordance with environmental regulations
- Introduction of water into the pipeline is a corrosion risk factor; the pipeline must be dried before it can be returned to service.
- Hydrostatic testing may be destructive; use of the method in highly populated areas is not desirable

To reduce the percentage of water used in hydrotesting, methanol is sometimes mixed with the water. This might partially solve a problem, but it introduces other issues that must be included in the overall integrity considerations.

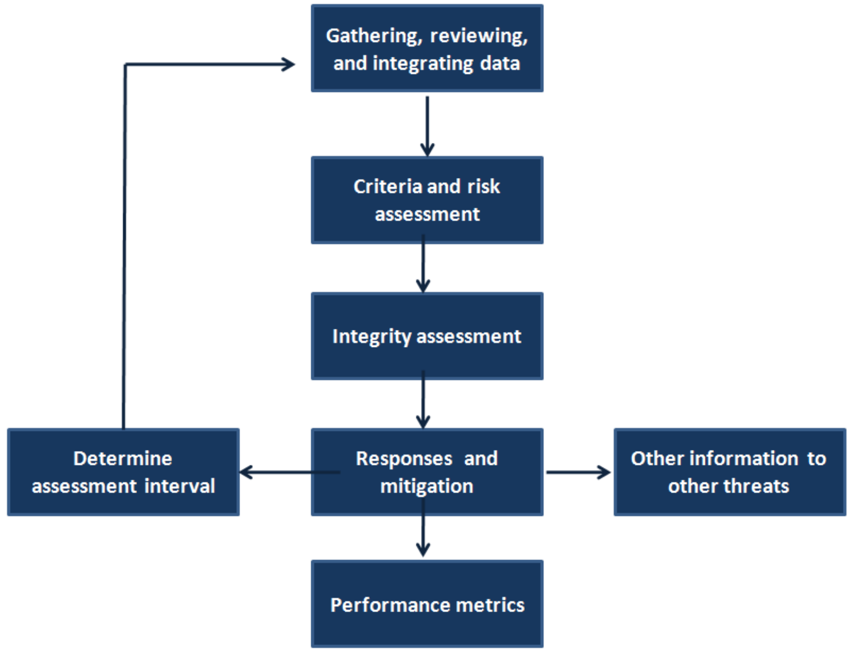


Figure 1.2 Prescriptive Integrity Management Plan, Manufacturing Threat, Construction Threat

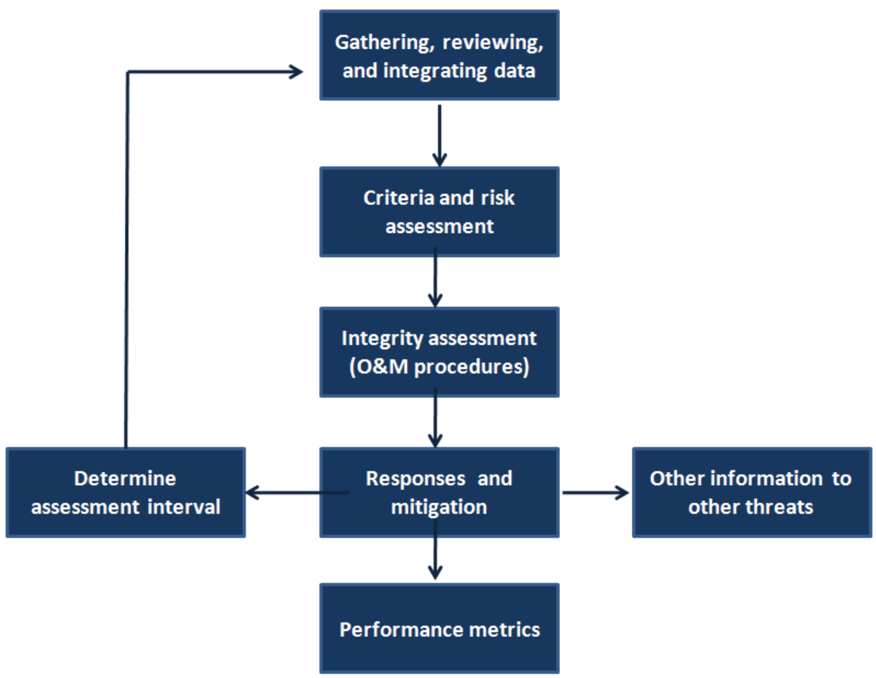


Figure 1.3 Prescriptive Integrity Management Plan, Equipment Threat, Third-party Damage Threat

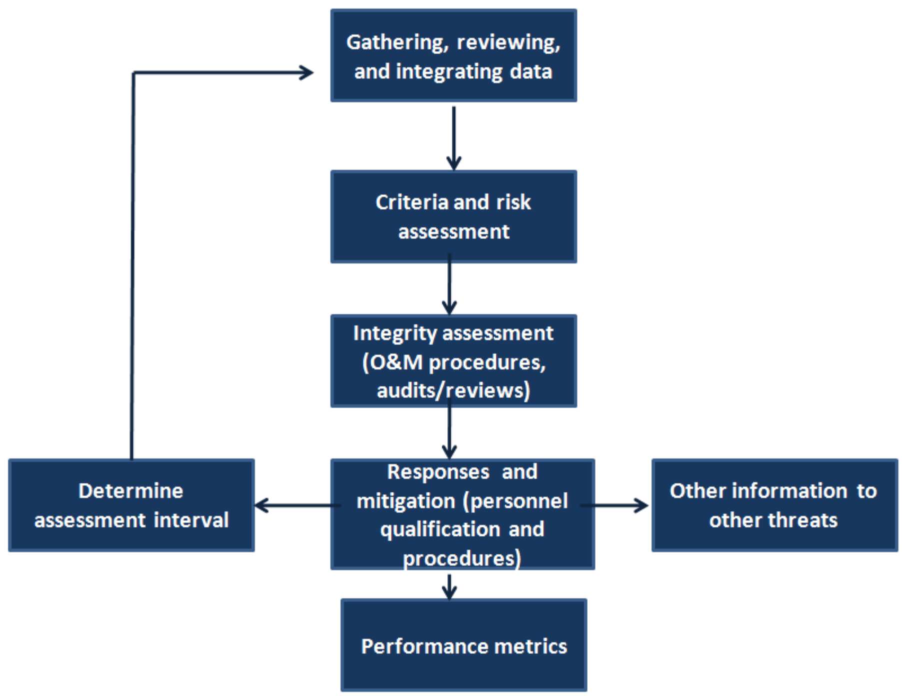


Figure 1.4 Prescriptive Integrity Management Plan, Incorrect Operations Threat

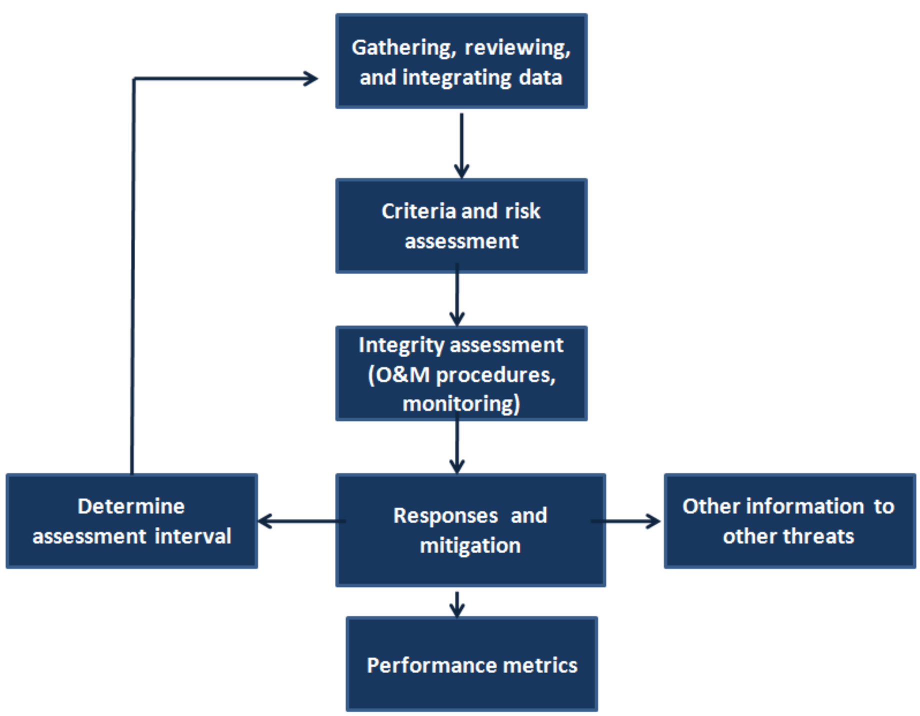


Figure 1.5 Prescriptive Integrity Management Plan, Weather-related and Outside Force Threat

1.4 Purpose of Pipeline Integrity Programs

Most pipeline integrity management programs are driven by regulations. It is now a regulatory requirement for most hazardous liquids and natural gas transmission pipeline operators in the U.S. to develop and implement a pipeline integrity program. Compliance with good regulations should benefit both the public and the pipeline operator. Therefore, it is necessary for the operator to structure the pipeline integrity program to maximize the benefits from:

- Public safety
- Goodwill and investor relations
- Reduced liability
- Environmental protection
- System reliability
- Asset preservation

Pipelines transport all of the natural gas and 60% of the petroleum liquids used in the U.S. and are well established as the safest mode of transportation. The infrastructure transporting natural gas and hazardous liquids pipelines works all day, every day of the year. The existing energy pipeline network in the United States, reported by OPS, is summarized in Table 1.1.

Table 1.1: Energy Pipelines in the United States

Hazardous Liquids Transmission	155,000 miles
Gas Transmission	322,000 miles
Total Transmission	**477,000 miles**
Gas Distribution	1,718,000 miles
ALL PIPELINES	**2,195,000 miles**

Billions of dollars are spent every year to ensure that gas and petroleum liquids are delivered for use by consumers in a safe, reliable and efficient manner. The challenge is to maximize the benefits to all of society.

As Figure 1.6 indicates, there are numerous potential threats to the pipeline integrity. One of the first challenges is to recognize the potential threats and establish a program to assess the significance of the threats so appropriate remedial actions can be taken within a comprehensive integrity program. Factors addressed by such a comprehensive program include:

- Construction materials and techniques
- Construction defects and damage
- Operations and maintenance procedures
- Third-party mechanical damage
- Protective coating system performance
- Cathodic protection system performance
- External, internal and atmospheric corrosion mechanisms
- Cracking mechanisms
- Earth and weather forces
- Device failures and malfunctions
- Incorrect operations and operating procedures
- Surveillance and security

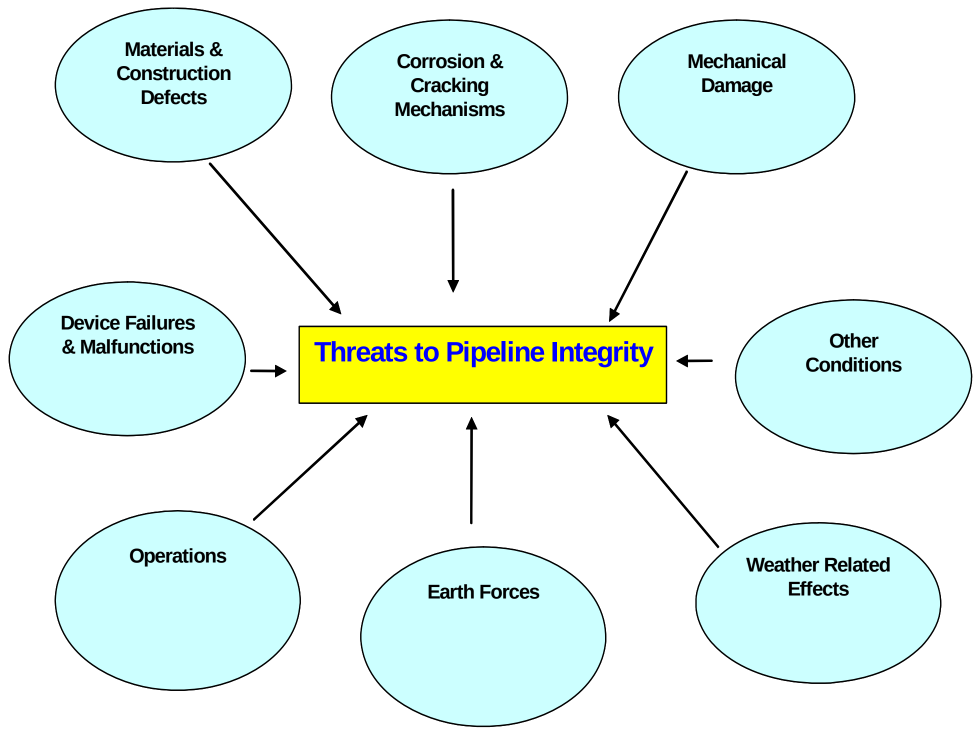


Figure 1.6 Potential Threats to Pipeline Integrity

The concepts of pipeline integrity do not differ between hazardous liquids and natural gas pipelines, but the regulatory requirements do; the goal of both gas and liquid integrity management programs is to improve pipeline safety. A typical pipeline integrity program must contain specific minimum elements and fulfill specific minimum requirements as detailed below:

- Written integrity management program
  - Risk factors assignments
- High consequence area (HCA) segments identification
  - Risk determinations
- Baseline assessment plan and schedule
  - Defect identification and repair
- Baseline assessments
  - Other remedial and preventive actions

- Information (data) integration, management of change, communication plan
  - Continual program improvement
- Information (data) analysis
  - Continual integrity assessment that minimizes risks to health, safety, and the environment (HSE)

The concepts of each step are relevant for liquid and gas systems and for prescriptive- or performance-based integrity management. However, the details of the regulatory requirements for each element of the process do differ between hazardous liquids and natural gas pipelines, principally because of the inherent differences of their criteria and risk assessments.

There are two general types of integrity management programs: prescriptive based, and performance based. A prescriptive-based risk assessment process follows preset conditions that result in fixed inspection, detection, and mitigation activities and time lines to produce the necessary results. The process relies on qualitative probability and consequence analyses to prioritize risk. Subject matter experts (SMEs) constitute the backbone of prescriptive-based risk assessment. SMEs are from the operating company and/or consultants who have expertise in specific areas of operation and have the necessary technical training and expertise to provide descriptive data using sound engineering judgment. The relevant regulatory bodies prescribe the prevention, detection, mitigation, and time lines for the periodic risk and integrity assessments. The term derives from the fact that the process depends on regulatory prescriptions.

Performance-based risk assessment does not follow preset conditions; it permits the operator more freedom and greater flexibility to meet or exceed the required results. It utilizes risk management principles and risk assessment to determine prevention, detection, mitigation and its timing.

The complexity level of the method used to assign specific failure probability and consequence values in prescriptive-based risk assessment depends on whether an initial or a repeat integrity assessment is planned. For initial assessment, any of the prescriptive-based methods could be utilized. Repeat assessments are based on more complex methodologies, i.e., quantitative, semi-quantitative, or combinations of both. A semi-quantitative methodology combines both quantitative and qualitative methods.

Integrity management program development should begin with identifying and articulating company-specific goals and objectives. **This is an extremely important first step since these goals and objectives guide the subsequent steps**. Whether the program is prescriptive- or performance-based, all integrity management programs need to contain the following elements as described [6.1] in ASME B31.8S – 2004:

- Integrity Management Plan
- Performance Plan
- Communications Plan
- Management of Change Plan
- Quality Control Plan

The Integrity Management Plan is developed by identifying all pipeline threats; integrating pipeline data from all sources; assessing risk; evaluating system integrity; and defining measures for mitigation. This iterative process is used until all threats are evaluated and processes are put in place to address the integrity threats. Each step in the IMP process, including strategies to prevent specific threats, to detect those that already exist, and to mitigate risk, should be documented rigorously. Any risk assessment methodology that can be technically supported can be used. The plan should include a schedule that targets pipeline segments at highest risk first. The IMP should also build in continuous improvement, i.e., incorporate new information and use new technology. Since a performance-based plan requires far more detailed data and analysis of the pipeline and its condition, you must use more comprehensive and detailed methodologies which in turn give you greater schedule and mitigation flexibility. In a prescriptive plan, less detail is required but the reassessment intervals may be shorter depending on regulatory prescriptions.

The Performance Plan evaluates the effectiveness of the program to meet company-specific goals and objectives. It focuses on steps to identify integrity risks, address identified threats, and advance the overall integrity of the pipeline system. The plan should require this evaluation be performed quarterly or annually, established metrics to measure the program's effectiveness. Selected metrics that evaluate the effectiveness of an integrity management program are shown in Table 1.2.

Provisions to revise the Integrity Management Plan, the Communications Plan, the Management of Change Plan and the Quality Control Plan as more information becomes available should also be included. The philosophy of this process is continuous improvement.

The Communications Plan addresses the dissemination of information to employees, the public, and local, state and federal authorities with jurisdiction over the pipeline. The plan includes regular, scheduled communications to report integrity initiatives and program results; using the company web site is an effective approach. The procedure to respond to specific requests should be addressed as well. Contact information should be provided to landowners in the vicinity of the pipeline in case of emergencies. The plan must also ensure emergency responders not only have all the contact information but are very familiar with the emergency reporting and damage prevention procedures.

Table 1.2: Selected Metrics for Integrity Management Program

Metric Description	Update Frequency
System Measures	
Total number of spills	Quarterly
Spills by cause	Quarterly
Number of leaks per segment	Quarterly
Implementation Process	
Total mileage tested	Quarterly
Number of segments completed	Quarterly
Program Effectiveness Measure	
Percent miles hydrotested	Quarterly
Average repair indications per mile	Quarterly
Percent cathodic protection of system	Annually
Risk Assessment and Improvement Measures	
Mileage of pipeline risk assessment	Quarterly
Aggregate pipeline risk measure	Annually
Program And Self Assessment	
Program assessment	Annually
Unit assessments	Quarterly
Communications and Public Awareness	
Internal IMP communications	Quarterly
IMP training/improvement sessions	Annually
Public awareness contacts	Annually

The Management of Change Plan should establish a formal procedure to identify changes and the impact of these changes on pipeline integrity. Since a pipeline system and its environment are constantly changing, whether changes are permanent or temporary, they need to be fully documented for future use in ongoing evaluations. "Management of Change" is discussed more fully in Chapter 12.

The Quality Control Plan generally addresses documentation, implementation and maintenance of company processes and procedures, including third party participation in pipeline integrity activities, such as Direct Assessment. As defined in ASME B31.8S-2004, quality control is the "documented proof that the operator meets all the requirements of their Integrity Management Program." Quality control is discussed more fully in Chapter 12.

1.5 Public Safety

As stated above, the goal of pipeline integrity management programs is to improve pipeline safety; their specific purpose is to:

- Minimize hazards to the general public
- Minimize leaks and spills

Described below are three historically important pipeline failures with significant individual and societal impacts.

Bellingham, Washington

A well publicized liquid pipeline failure occurred in June, 1999, on a 16-inch diameter gasoline pipeline in Bellingham, Washington, killing three people. Two young boys were playing with a lighter in a creek into which over 200,000 gallons of gasoline had flowed from a pipeline rupture. The gasoline ignited, causing an explosion that killed both boys. Everything along a mile and one-half section of the creek was burned (Figure 1.7). Vapors from the leak also caused a fisherman to collapse and drown. Eight additional injuries were reported. Property damage was over $45 million.

Figure 1.7 Bellingham, Washington

Carlsbad, New Mexico

Perhaps one of the most widely publicized pipeline failures associated with internal corrosion is the pipeline incident at Carlsbad, New Mexico, in 2000. A 30-inch natural gas transmission pipeline ruptured; the gas ignited and burned for 55 minutes. Twelve people were killed and their vehicles destroyed. Debris from the rupture was found as far away as 287 feet northwest of the 51-foot by 113-foot crater that was created by the rupture. Three pieces of pipe were blown out, all of which showed evidence of internal corrosion (Figure 1.8). Evidence of internal corrosion was verified by the presence of corrosion pits and decreased wall thickness. The corrosion pits observed were interconnecting and showed striations and undercutting features that are typical of microbial activity. Other contaminants inside the pipeline such as moisture, chloride ions, and hydrogen sulfide contributed to the corrosion.

Figure 1.8 Carlsbad, New Mexico
(http://ops.dot.gov/regions/southwest/carlsbad/photo.htm)

In July, 2003, a hazardous liquids pipeline failed in Tucson, Arizona, resulting in the release of approximately 10,000 gallons of gasoline. The gasoline showered several homes that were under construction, but there were no injuries or fires. The pipe was 8-inch diameter installed in 1955 with coal tar coating. The pipe material was electrical resistance welded (ERW), Grade X-42. The cause of the pipeline rupture was stress corrosion cracking along the long weld seam of the pipe.

Figure 1.9 Tucson, Arizona (http://doney.net/aroundaz/gas_lines.htm)

Accident Summaries

In a 2006 report generated from the OPS website, the number of incidents, fatalities and injuries are summarized for the 20-year period from 1986 to 2006. This is presented in Table 1.3.

Table 1.3: Reported Injuries and Fatalities

System Type	Fatalities	Injuries
Hazardous Liquids Transmission	44	272
Natural Gas Transmission	60	244
Natural Gas Distribution	344	1,457
TOTAL	**448**	**1,973**

1.6 Reliability and Deliverability of the Pipeline System

The most important contribution to reliability and deliverability that comes from a pipeline integrity management program is to ensure continuous pipeline operations. A pipeline failure takes the line out of service, often for an extended period. This interrupts supply and/or causes shortages that can directly impact the public. Indirectly, failures can result in lost electric power generation and/or limited availability of heating fuel that could result in life threatening circumstances. Such events can also impede industrial production of products that public relies on in every day life.

Pipeline integrity operations can also enhance product flow through the pipeline system. An internally clean pipeline helps maintain throughput capacity and desired flow parameters; it also reduces energy operating costs for pumps or compressors. Build up of corrosion scales or tuberculation can reduce the inside diameter of the pipeline; paraffin build-up can also restrict product flow. Some pipeline operators use cleaning pigs periodically to clear the pipeline of any debris or foreign matter that can be the catalyst for internal corrosion. A pipeline operator concerned about internal corrosion will keep the pipeline as clean as possible and clear of debris.

For example, when H_2S exists in a natural gas well or pipeline and is dissolved in brine, there is no oxygen or other oxidizing agent with it. Under these conditions, the dissolved H_2S will attack iron and non-acid-resistant alloys. The general corrosion reaction of H_2S with iron is:

$$H_2S + Fe \longrightarrow FeS + H_2$$

The iron sulfide (FeS) produced by this reaction generally adheres to steel surfaces as a black powder or scale and can impede pipeline operations (Figure 1.10).

Figure 1.10 Black Powder

1.7 Asset Preservation

The life of a transmission pipeline system is highly dependent on how well the pipelines have been protected from corrosion. It was previously noted that the United States energy pipeline system consists of 477,000 miles of gas and hazardous liquids transmission pipelines. At an estimated replacement cost[1.2] of $1,117,000 per mile, the asset replacement cost is $533 billion. Similarly, there are 1,718,000 miles of natural gas distribution mains and 650,000 miles of service lines, serving 55 million locations in the United States[1.2]. At an estimated replacement cost[1.2] of $250,000 per mile, the asset replacement cost is $592 billion.

The asset value of the regulated pipeline system is therefore over one trillion dollars. These are the pipeline assets that need to be preserved and their service life extended. Other assets are also affected by pipeline operations incidents. In the same 2006 report from the OPS website referenced in Section B, the property damage from pipeline failures for the 20 year period from 1986 to 2006 appears in Table 1.4.

Table 1.4: Property Damage from Pipeline Failures

System Type	Property Damage
Hazardous Liquids Transmission	$1,111,800,000
Natural Gas Transmission	$718,100,000
Natural Gas Distribution	$737,400,000
TOTAL	**$2,567,300,000**

1.8 Maintenance Optimization

In an effective pipeline integrity program, maintenance expenditures are optimized by reducing risks. Proper prioritization means the most important programs will be funded first. Departments are staffed, personnel are trained and operators qualified as part of the overall program. In a good integrity management plan, company management will know the pipeline integrity management rules; so operating budgets and capital expenditures will be funded to support the program.

1.9 Economics

The total cost of the June, 1999, gasoline pipeline failure and explosion in Bellingham, Washington will exceed a billion dollars in fines from the U.S. Department of Transportation, the U.S. Environmental Protection Agency, and the Washington State Ecology Department, as well as civil and criminal penalties.

The August, 2000, natural gas pipeline failure in Carlsbad, New Mexico resulted in a $2.5 million fine and five safety citations for failure to ensure internal corrosion control resulting in 50% wall loss in the 50 year old pipeline.

The direct costs are only a small fraction of the cost of a pipeline incident that releases product into the environment. Other costs include:

- Lost revenue from interruption of pipeline operations
- Lost product

- Expenditures for repair and the cost of property damage
- Public liability including increased insurance costs
- Public image including investor relations
- Civil and possibly criminal penalties

In today's environment, pipeline integrity should have the attention of the highest levels of management, including corporate officers and the boards of directors, who have the fiduciary responsibility to operate the company in the best interests of the public, the investors, and the employees.

Benefit-to-Cost of Corrosion Protection

Because of the regulatory environment in which energy pipelines operate, there is little published about the benefit-to-cost ratio of corrosion control and integrity programs. In the water industry, this is not the case. Corrosion protection programs are implemented to save money, since there are no regulatory requirements for protective coatings and cathodic protection. As a result, numerical data are more frequently collected about the benefits and costs of corrosion protection. One such report indicates that the benefit-to-cost of corrosion protection for steel water pipelines is 24 to 1.[6.3] Included are all costs required to reach the designated design life of 100 years, including capital costs, CP operating and maintenance costs and CP system upgrades and/or replacement. When the net present value of pipe replacement was compared to the corrosion protection costs, the benefit-to-cost ratio was 24 to 1. Because water pipelines typically pose less risk to public safety and the environment, these data are likely conservative when applied to energy pipelines for controlling the threat of external corrosion.

References

1.1. ASME B31.8S – 2004, ASME Code for Pressure Piping, B31, Supplement to ASME B31.8, "Managing System Integrity of Gas Pipelines." ASME, January 14, 2005.
1.2. FHWA-RD-01-156. "Corrosion Cost and Preventive Strategies in the United States." U.S. Department of Transportation, Federal Highway

Administration, Office of Infrastructure Research and Development, September 30, 2001: pp.viii, ix.
1.3. Bianchetti, Ron. "Managing Water Infrastructure," MP, (July, 2003): pp. 8.
1.4. Hevle, Drew. "Major Pipeline Outlines Its Compliance Plan for Integrity Management," Pipeline and Gas Journal, (March, 2004): pp. 32-35.

Chapter 2: Managing Corrosion

After completing this chapter, students should be able to:

- Identify the eight forms of corrosion.
- Describe the three time-dependent threats to pipeline integrity.
- Identify and describe the tools used for corrosion detection methods.
- Describe the corrosion mediation and re-mediation methods.

2.1 Forms of Corrosion

Pipeline corrosion is the deterioration of pipeline material due to reaction with its internal and/or external environments, including stress corrosion cracking, each of which could compromise pipeline integrity leading to leakage or blow-out (Figure 2.1). Most metals are thermodynamically unstable and will tend to seek a lower energy state, such as an oxide or some other compound. This process by which metals, exposed to the environment, convert to the lower-energy compounds is known as corrosion. Corrosion is the primary reason for aging and deterioration of buried pipelines. Indeed, it is the second leading cause of pipeline failure.

Figure 2.1 External Corrosion

The following four conditions must exist simultaneously in order for corrosion to take place (Figure 2.2):

- An anode where an oxidation reaction takes place accompanied by loss of electron(s), e.g. iron dissolving to an ion Fe^{++} with a loss of two electrons, $2e^-$
- A cathode where reduction reaction takes place accompanied by gain of electron(s), e.g., the electrons produced at the anode are consumed
- A metallic electrical connection between the anode and the cathode, e.g., the pipeline wall
- Electrolyte, e.g., soil or water with dissolved ions

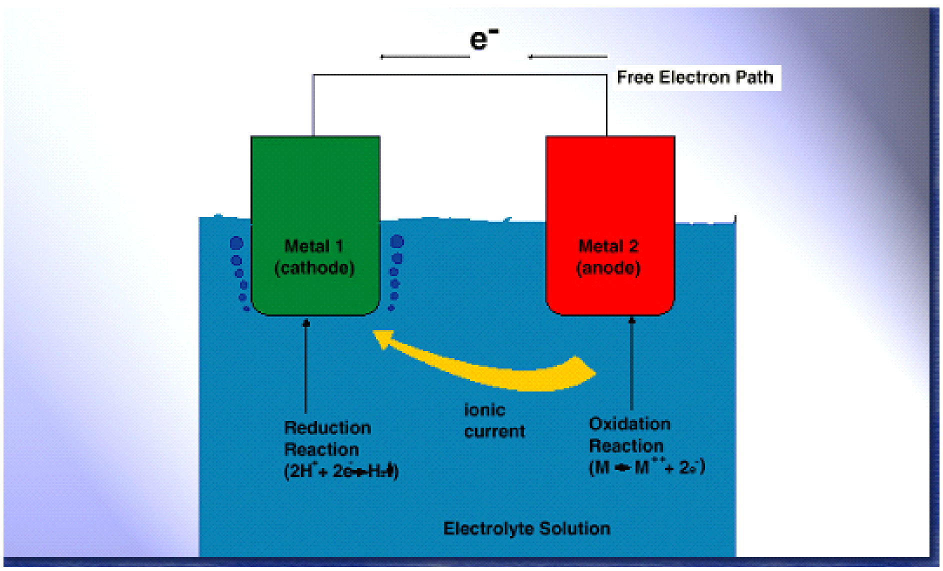


Figure 2.2 Four Conditions for Corrosion to Occur

Please note that the anode is at a higher energy state than the cathode. Any metal surface will consist of many electrodes (anodes and cathodes) connected by the body of metal itself (Figure 2.3). These electrodes are microscopic and their precise location is not fixed. In the presence of an electrolyte, these anodes and cathodes can function as corrosion cells leading to the conversion of the metal to corrosion products.

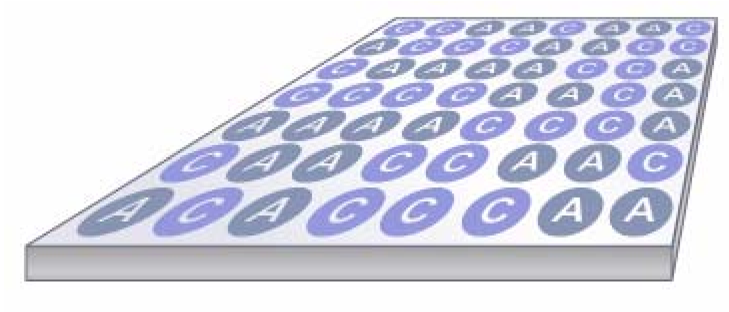


Figure 2.3 Represents Surface of a Pipe

Corrosion reactions in pipelines involve the transfer of charge between the metal and the electrolyte, and this is termed electrochemical. At the anode, oxidation (corrosion) occurs by the loss of metal atoms from the structure to the electrolyte as ions. An example of an oxidation reaction is shown in the following equation.:

$$Fe \longrightarrow Fe^{++} + 2e^{-}$$

In this case, metallic iron (Fe) is oxidized (loses electrons) to the Fe^{2+} state as an ion in the solution, thereby producing two electrons (e^-). At the cathode, the electrons produced from the anodic reaction are consumed in reduction reactions. Many cathodic (reduction) reactions are possible including hydrogen evolution and oxygen reduction shown below.

$$2\,H_2O + 2\,e^{-} \longrightarrow H_2 + 2\,(OH^{-}) \quad \text{(hydrogen evolution)}$$

$$2\,H_2O + O_2 + 4\,e^{-} \longrightarrow 4(OH^{-}) \quad \text{(oxygen reduction)}$$

The characteristics of anodic and cathodic reactions are summarized in Table 2.1.

Table 2.1: Main Characteristics of Anodic and Cathodic Reactions

Anodic Reactions	Cathodic Reactions
Oxidation	Reduction
Corrosion	No corrosion
Loss of electrons	Gain of electrons

The primary reason corrosion occurs is based on thermodynamics. Thermodynamics is the science of energy flow. In many cases, this energy flow is in the form of heat. In the case of corrosion reactions, the amount of heat generated is too low to measure. Rather, the flow of energy in corrosion reactions is in the form of electrical energy resulting from electron flow. It is this flow of energy that determines the direction of chemical and corrosion reactions. For these reactions to occur spontaneously, the final energy must be lower than the initial energy. In the case of engineering materials such as steel, the iron used as the primary constituent of the steel is in a higher energy state than its natural state. The natural state for iron is primarily in the form of ferric oxide (Fe_2O_3) ore, which also is a common form of rust produced during corrosion of iron and steel. Iron and steel tend to revert back to Fe_2O_3 (or "iron oxide"). This is shown schematically in Figure 2.4.

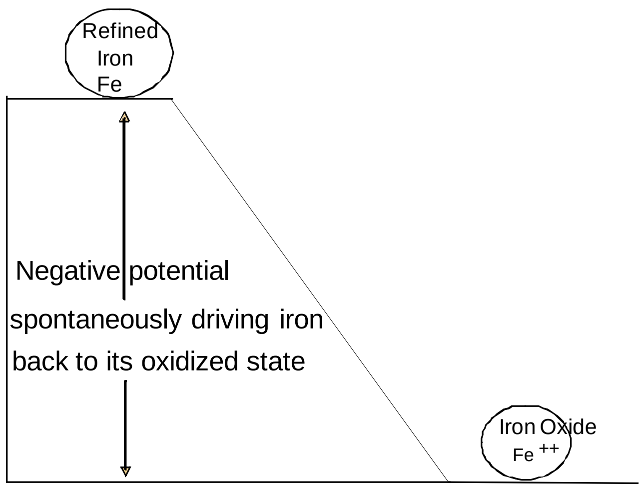


Figure 2.4 Refining of Iron Ore

Because electrical energy is transferred during corrosion processes, electrical measurements are used to describe the processes. They include measurements of potential and current. Measurement of electrical potential is a method to measure energy differences. For corrosion, the anode is at a higher energy state than the cathode and thus electrons flow from the anode to the cathode. This electron flow is dependent on the energy difference between the anode and the cathode that is manifested in a difference in potential between the anode and the cathode.

The potential difference between the anode and cathode can arise by a number of different means. The most intuitive case occurs when two different materials are electrically connected (galvanic) together, such as in the case of an aluminum alloy sacrificial anode protecting a steel storage tank as the cathode. Another example is a concentration cell where differences in the environment exist at different locations on the same structure. An example of this is crevice corrosion in the form of a differential aeration cell. In a differential aeration cell, oxygen is present and oxidation of iron occurs inside the crevice or occluded/hidden region.

Corrosion on an internal section of a piece of pipeline steel is shown schematically in Figure 2.5. In this case a region of the pipeline acts as the anode and a separate region acts as the cathode. The distance between these areas can be as small as a few millimeters and can result from differences in local chemistry, repairs made using new piping materials, and many other reasons. It should also be noted that at any given time one area might be the anode and another the cathode, but these can switch if conditions change. Thus, just because one area is considered the anode does not necessarily mean it will always be the anode.

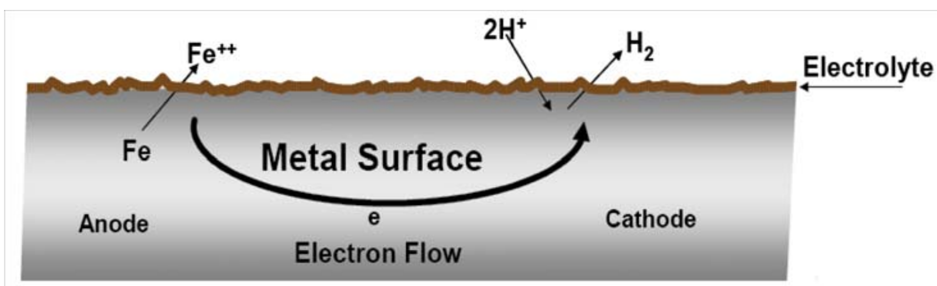


Figure 2.5 Anode-Cathode Regions on a Pipeline and the Corrosion Chemistry

For electrochemical corrosion to occur, the metal surface must be wetted by an electrolyte that conducts ionic current from the anode to the cathode of the corrosion cell. Conductivity is a numerical expression of the ability of a substance to conduct an electric charge or current due to the presence of positively or negatively charged ions in an electrolyte solution. Conductivity depends on the concentration, mobility, and valence of the ions, hence, it is proportional to the total salt concentration or the amount of metal dissolved in the electrolyte solution.

Theoretically, the higher the conductivity of an electrolyte, the greater the chance for corrosion. Conductivity is the reciprocal of resistivity. The less conductive the electrolyte, the greater the resistance to electrolytic current flow, the slower the corrosion reaction. The amount of electrolytic current flow is directly proportional to the amount of metal that dissolves (i.e., corrosion). For example, one ampere of electrolytic current in one year represents a loss of 20 pounds (9.1 kilograms) of iron.

Water is a solvent that dissolves most inorganic matter as well as some organic compounds. The dissolved solids, originating from a production system, increase the corrosivity of the water and may contribute to scaling or fouling.

Wells, having measurable water cut, are identified at the gathering center by their bottom sediment and water content. The presence of water has a serious corrosion implication for downhole equipment, gathering system flowlines, and pipelines. The concentration of hydrogen ions is expressed as pH. The pH value of a fluid is a measure of the acidity or alkalinity of an electrolyte solution. The lower the pH of a solution, the greater its hydrogen ion concentration and the greater the solution's influence on corrosion rates. On the other hand, higher pH or higher alkalinity does not always result in less corrosion.

In what follows, the various forms of corrosion would be viewed as the controlling mechanisms for internal corrosion, external corrosion, and/or stress corrosion cracking. Hence, the forms of corrosion will be generally discussed first. The causative circumstances for internal, external and SCC corrosion phenomena will then be discussed under separate headings. The key forms of corrosion presented in Table 2.2 include the following: uniform or general corrosion, localized corrosion, galvanic corrosion, microbiological influenced corrosion (MIC), environmentally assisted cracking (EAC), intergranular corrosion (IGC), de-alloying cleavage and velocity-related corrosion.

2.1.1 Uniform or General Corrosion

This is the most common form of corrosion and results from a uniform electrochemical reaction with a more or less predictable corrosion rate. The material progressively gets uniformly thinner as the corrosion progresses. This sort of corrosion is distributed uniformly over the metallic surface even when it occurs in an isolated location (Figure 2.6). Its characteristic uniformity implies that its rate could be utilized for an appropriate equipment design. Uniform corrosion results in a gradual reduction of wall thickness and the loss of pipe strength in conjunction with overpressure can cause pipeline ruptures to occur. This form of corrosion occurs in either the internal or external environments of pipelines. For general corrosion, an allowance of 1.5 mpy wall loss is usually associated with carbon steel pipeline in a very low corrosion environment, e.g. dry gas with the possibility of operating below the dew point.

Figure 2.6 External Surface of a Pipeline With Uniform Corrosion

2.1.2 Localized Corrosion

This includes pitting attack resulting in holes in metals and crevice corrosion in areas that are hidden from the bulk environment such as under tape-wrap coatings, various deposits, sediments, and corrosion products. Pitting corrosion is autocatalytic with the pits growing in the direction of a gravitational pool. In some cases, several pits may become interconnected resulting in failures of pipelines that were otherwise in excellent condition. Figure 2.7 illustrates an example of pitting corrosion on a section of corroded carbon steel.

A bicarbonate solution is generally more corrosive than fresh water and it causes pitting corrosion. This effect can be ascribed to two factors; (1) bicarbonate ion is a potent electrolyte and the higher the conductivity of an electrolyte the greater the chance for corrosion, and (2) the presence of a bicarbonate is often associated with the presence of carbon dioxide and CO_2 results in "sweet corrosion" characterized by pitting.

The mechanisms of high pH SCC and near neutral pH SCC on a pipeline's external surface is believed to be associated with localized pitting whose path is determined by the local threshold tensile stresses for the susceptible pipeline material. Crack initiation often starts at sites where pitting processes occur. If the incipient pitting cracks in CO_2-dominated environment are deep and narrow with rapid penetration, stress corrosion cracking may result from the interaction of operating stress and the pitting. The cracks may indeed reach a depth at which pipeline failure may result from third party contact or excessive pipe pressure. Pitting corrosion is normally surrounded by a non-corroded region, a noted characteristic of SCC failure.

Figure 2.7 Corroded Carbon Steel Illustrating an Example of Pitting Corrosion

Dissolved oxygen causes severe pitting attack even at concentrations lower than 50 parts per billion. Because it is present in the atmosphere and is sufficiently soluble in water, it is present in all surface waters. Chloride anions promote an extremely aggressive localized corrosion (pitting, crevice, etc.). Chloride ions are believed to be the key components that cause corrosion in stainless steel, which fails mainly by pitting and cracking. Chloride anions represent a significant percentage of total dissolved constituents of most service waters.

Crevice corrosion is also autocatalytic, occurring in small stagnant electrolytes under bolts, rivets, washers, deposits of mud or sediment (Figure 2.8). The stagnant electrolyte is in contact with the hidden steel surface. This becomes the active (anodic) component where an oxidation reaction takes place. The non-stagnant electrolyte is in contact with the exposed metal surface. This surface becomes the passive (cathodic) component, where a reduction reaction takes place. Hence, metal dissolution occurs within the stagnant electrolyte leading to the formation of an ever- deepening cavity normally referred to as crevice corrosion.

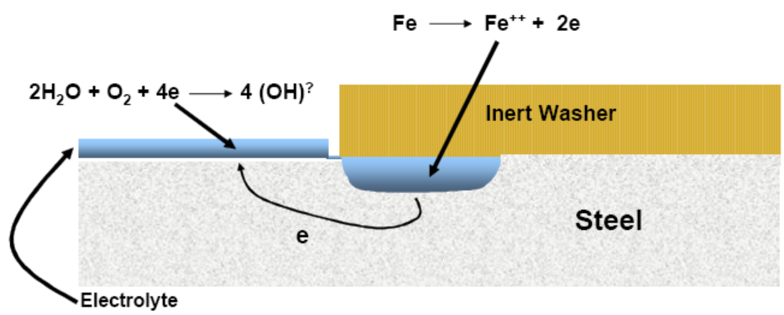


Figure 2.8 A Schematic Illustration of a Typical Crevice Corrosion Cell

The electron released at the anode is conducted through the steel to the cathode where it is consumed in the cathodic reduction reaction. Ionic current is conducted within the electrolyte connecting both the anode and the cathode of the corrosion cell. This form of corrosion occurs in either the internal or external environments of pipelines.

2.1.3 Galvanic Corrosion

Coupled bimetallic materials give rise to galvanic corrosion as the active metal acts as the anode (corrodes) and the more noble (passive) material acts as the cathode. ASTM G15-83 defines “passive” as the state of a metal surface characterized by low corrosion rates in a potential region that is strongly oxidizing for the metal. Conversely, “active” is the state of metal surface characterized by high corrosion rates in the same oxidizing region.

A galvanic cell could also be established on the same material with two portions at different ages. This happens when a newer material of the same carbon steel is used for pipeline repair. Figure 2.9 illustrates a schematic of a bimetallic galvanic cell with the material on the right (cathode, metal 2) being the older material and that to the left (anode, metal 1) being the newer material.

The large-anode small-cathode dichotomy might be at play however, as there is more of the old material than the new. The anode-cathode area ratio principle is particularly germane for a galvanic cell with a large cathode and a small anode. This situation will result in accelerated corrosion of the anodic material. This form of corrosion does occur in both internal and external environments of pipelines. Figure 2.10 better illustrates the anode-cathode area ratio principle.

The area principle states that the overall corrosion rate is equal to the total cathodic area exposed to the electrolyte (i.e., corrosion will occur only as fast as the cathodic reaction can occur). An area ratio that is extremely corrosive has a large cathode area and a small anode area in which the anode corrosion rates are 100 to 1,000 times greater than when the areas are equal. The overall oxidation rate must match the overall reduction rate. The opposite ratio is also true: a small cathode area and a large anode area result in a lower corrosion rate than when the areas are equal.

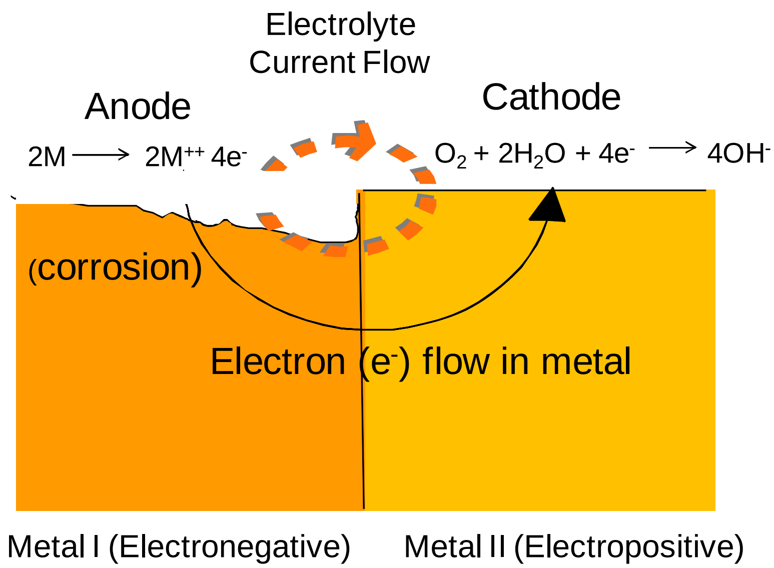
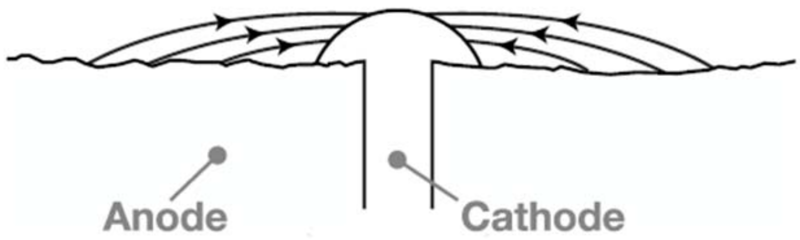


Figure 2.9 A Schematic of a Bimetallic System Illustrating Galvanic Corrosion

When using a coupon for internal corrosion monitoring, the coupon holder must be electrically isolated from the coupon through the use of insulating materials, such as nylon or Teflon™, particularly if the two are made of dissimilar materials.



A) Large anode area, small cathode area showing relatively insignificant attack over a wide area of sheet.

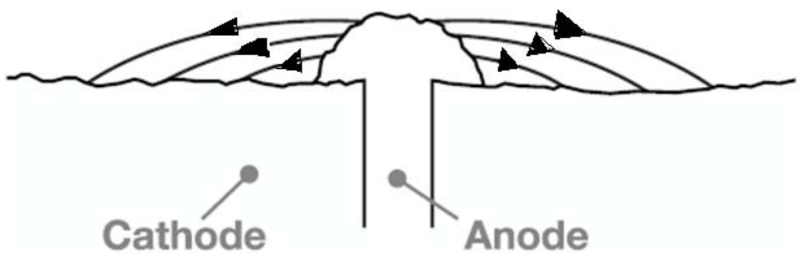


Figure 2.10 A Schematic Illustrating The Anode-cathode Area Ratio Principle

2.1.4 Microbiological Influenced Corrosion (MIC)

MIC is the degradation of a pipeline by the metabolic products of microorganisms such as bacteria, fungi, algae, and protozoa. Bacteria associated with corrosion are usually classified based on their oxygen requirements. Aerobic bacteria require air or oxygen to live and anaerobic bacteria require an environment without air or oxygen. Obligate bacteria can only exist in either aerobic or anaerobic environment, but not both. On the other hand, facultative bacteria is able to survive in either aerobic or anaerobic environments. Sessile bacteria are attached to the surface and planktonic bacteria are free-floating. Bacteria like sulfate reducing bacteria (SRB), general aerobic bacteria (GAB) and general anaerobic bacteria (GanB) are the most common bacteria encountered. Microbial communities include acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB). MIC does occur in both internal and external environments of pipelines. Figure 2.11 illustrates a bacteria colony associated with corrosion products.

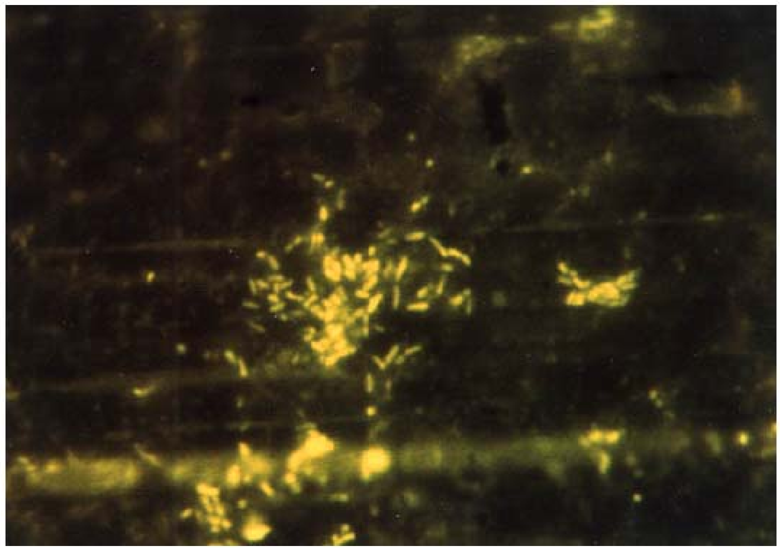


Figure 2.11 A Fluorescent Microscopic Examination of a Surface "Replica" of Bacteria Colony Associated With Corrosion Products

In general, MIC occurs where the bulk solution pH ranges between 5 and 9, and total dissolved solids are less than 200,000 ppm. SRB do not require more than 7.5 ppm of sulfate to generate substantial hydrogen sulfide (as a metabolic product), which is not normally present in sub-surface formations. Hydrogen sulfide (H_2S) is a colorless, poisonous gas that has a characteristic rotten egg odor at low concentrations. Dissolved in water, H_2S has a significant enough pH and usually causes pitting of carbon steel, depending on the type of film formed on the metal surface. Corrosion due to H_2S attack is often referred to as "sour" corrosion and oil and gas production operations containing H_2S are referred to as sour service.

Generally, when H_2S exists in a natural gas well or pipeline and is dissolved in brine, there is no oxygen or other oxidizing agent with it. Under these conditions, the dissolved H_2S will attack iron and non-acid-resistant alloys. The general corrosion reaction of H_2S with iron is as follows:

$$H_2S + Fe \qquad FeS + H_2$$

The iron sulfide (FeS) produced by this reaction generally adheres to steel surfaces as a black powder or scale. FeS scale "coating" is cathodic to the steel and may result in deep pitting where there are breaks in the continuous scale layer whereby the exposed iron surface becomes the small anode in a "sea" of FeS cathode. The deposits of iron sulfide can also accelerate the corrosion reaction already in progress through the process of under-deposit corrosion. Another problem that may result from H_2S is sulfide stress cracking, a spontaneous brittle failure that occurs in steels and other high strength alloys when exposed to moist H_2S and other sulfuric environments.

The most prevalent corrosion reaction under anaerobic conditions is the reduction of hydrogen ions to hydrogen atom at the cathode. Hydrogen sulfide interferes with the production of molecular hydrogen at the cathode, enabling the penetration of atomic hydrogen into the crystal lattice of the metal. This is the genesis of a variety of environmentally assisted cracking such as hydrogen blistering; the formation of hydrogen gas in voids in the steel that build up and cause blistering.

Other products of microbial metabolism in produced water are weak organic acids, formed by severe pressure and temperature conditions. Typical organic acids in this category are the carboxylic acids, also known as short-chain fatty acids. These organic acids could be present in ionic forms either as free acids or as salts of other cations. The most common are derived from the following salts: formates, acetates, propionates, etc., and they all promote corrosion. For example, the presence of trace quantities of low-molecular-weight organic acids (formic, acetic, or propionic acids) in the presence of CO_2 can cause increased corrosion due to the acidity of the organic acids and the formation of soluble corrosion products (e.g., iron acetate). Organic acids are a source of significant hydrogen ion concentrations, which explains their corrosivity to metals. The greater the hydrogen ion concentration, the lower the pH, the greater the solution's influence on corrosion rates resulting in an expected increase in corrosion rate.

Microbial communities also harbor alcohols, carbon dioxide, ammonia, carbon dioxide, and other metabolic by-products that are capable of corroding various metals under appropriate conditions. Microbes can "consume" oxygen, sulfates, chlorides, and produce a variety of by-products that concentrate in corrosion pits, crevices, under tape-wrap coatings, and/or deposits. They are able to break down passive surface films and accelerate corrosive attack by a variety of mechanisms. The living microbial communities create biofilms capable of capturing and accumulating all sorts of solids from the fluid system. This could take place inside a liquid pipeline with low velocity, high water cut, and fine suspended sand particles that could trap water around the 6 o'clock region of the pipeline. MIC also occurs in the soil on the external surfaces of buried pipelines.

Microbiological Testing: Serial dilution culture tests and/or fluorescence microscopy examinations (or other microbiological techniques) may be performed on fresh samples of liquids or corrosion products in order to establish the presence and concentration of bacteria (colonies/mL or colonies/gram) within the corrosion damage site. Microbiological testing of samples (e.g., water, soil, sludge, etc.) is a reflection of the system environment and can indicate whether bacteria are present. Note that microbiological analysis of the bulk fluids only gives a "snapshot" for levels of free-floating (planktonic) bacteria present in the system at that particular time; it may not be representative of the levels of bacteria attached (sessile) to pipe surfaces. The presence of bacteria does not prove that any corrosion present was due to MIC. No relationship between levels or types of viable bacteria (APB, SRB, facultative anaerobes, etc.) and the occurrence of actual microbial corrosion has been documented in the literature to date.

Liquid media vials for culturing and semi-quantitatively enumerating viable APB, SRB, facultative anaerobes, or other desired groups of bacteria are commercially available. Alternatively, microbiological test kits containing specified media formulations, syringes, sample containers, etc. can also be obtained from some vendors. Serial dilutions of liquid culture media are generally used in industry for estimating viable bacteria populations. It is important when following sampling and culturing procedures (NACE TM0194, "Field Monitoring of Bacterial Growth in Oil and Gas Systems") that minimal exposure of samples to oxygen occurs so that any anaerobic bacteria present may be successfully grown.

Typically, media vials/bottles are arranged into a “dilution series.” Normally, a three- to five-vial series is used. Additional vials may be used in a series if a higher “maximum detection limit” estimate for viable bacteria levels is desired.

2.1.5 Environmentally Assisted Cracking (EAC)

Environmentally assisted cracking (EAC) is the brittle fracture of a normally ductile material in which the corrosive effect of the environment is a causative factor. This form of corrosion occurs in the internal or external environments of pipelines. EAC includes a variety of cracking failure mechanisms that are enhanced or altered by the environment. Such mechanisms include:

- Stepwise cracking (SWC)
- Hydrogen-induced cracking (HIC)
- Hydrogen embrittlement (HE)
- Corrosion fatigue
- High pH SCC
- Near neutral pH SCC

Ordinarily, the most prevalent corrosion reaction under anaerobic conditions is the reduction of hydrogen ions to hydrogen atom at the cathode. However, hydrogen sulfide interferes with the production of molecular hydrogen at the cathode, enabling the penetration of atomic hydrogen into the crystal lattice of the metal. This is the genesis of HIC, SWC and HE.

SWC occurs when atomic hydrogen migrates into the internal discontinuities (e.g., inclusions, laminations) and recombines to form hydrogen gas. If the atomic hydrogen migrates into the internal discontinuities near the surface of the pipeline and recombines to form hydrogen gas, blister-like bulges and HIC may occur.

Hydrogen embrittlement is caused by internal migration of atomic hydrogen that causes a loss of ductility of pipeline steel. In ferritic steel, the diffusion coefficient of the hydrogen atom is similar to that of salt in water. Besides, atomic hydrogen tends to diffuse towards the region of the material with high triaxial tensile stress where the structure is already dilated. It assists the development of local plastic deformation and embrittles the region. This makes fracture and cleavage easier. Eventually, catastrophic cracking failure occurs. This is a form of SCC, which could be an intergranular or transgranular mechanism. For SCC caused by hydrogen embrittlement, the higher the alloy strength, the more susceptible the material is to SCC.

Environmentally assisted cracking (EAC) encompasses a variety of cracking failure mechanisms that are enhanced or altered by the environment. The mechanisms include hydrogen-induced cracking (HIC), hydrogen embrittlement (HE), and stress corrosion cracking (SCC). HIC occurs when the material is infiltrated by atomic hydrogen (which can be generated as a cathodic reaction through cathodic protection), resulting in "stepwise" cracking or "blister cracking." After the hydrogen atoms enter the material, they tend to migrate and collect at internal discontinuities (e.g., inclusions, laminations) that form pockets of hydrogen gas. Hydrogen blistering, related to HIC though not strictly a cracking mechanism, occurs when the hydrogen entering into a metal accumulates at internal discontinuities near the metal surface. It results in the formation of blister-like bulges. HE is also caused by internal hydrogen but is typically manifested as a loss in ductility in high-strength materials. SCC involves the conjoint effect of a corrosion process and cracking in the presence of a tensile stress. Sulfide stress cracking is a form of cracking associated with the presence of H_2S. The source of stress can include external loading, internal pressurization, or residual stress (e.g., from welding).

The high-pH and near-neutral pH SCC will be discussed in the section on SCC below.

2.1.6 Intergranular Corrosion (IGC)

Intergranular (or intercrystalline) corrosion occurs at the grain boundaries only, not in the matrix or the continuum of the material. It is occasioned by the accumulation of impurities or precipitate that are capable of creating a local electrochemical cell action at the grain boundary. For example, the impurities or precipitates whose corrosion potential are dissimilar to the solid solution would create a local corrosion cell at the grain boundary. Intergranular corrosion are frequently associated with deposits covering the metal surface.

The formation of chromium carbide, at the grain boundary in austenitic stainless steel at the heat affected zone, depletes the stainless steel of chromium, leaving the chromium-depleted zone susceptible to intergranular corrosion.

This is an active corrosion path along the grain boundaries of the susceptible material with little or no perceptible change in the bulk or the surfaces of the material, which remain passive. This accelerated corrosion process could occur in the absence of stress with the corrosion path acting essentially as a form of crevice corrosion. In the presence of applied stress, the IGC fault lines could develop into cracks that could result in catastrophic failure. This is akin to SCC; it could also be corrosion fatigue if fatigue stress is a caustive factor. Indeed, intergranular corrosion-fatigue cracks are sometimes difficult to differentiate from stress-corrosion cracking. The fatigue stress could be cyclic bending stresses or cyclic axial stresses generated by cyclic thermal expansion and contraction.

A corollary of intergranular fracture is transgranular (or transcrystalline) fracture. In this instance, the cracks pass through the metallic grains rather than follow their boundaries. An example is the SCC of 18%-chromium, 8% nickel stainless steel Type 304 (UNS S30400) subjected to tensile stress in a hot chloride solution environment. Figure 2.12 illustrates examples of intergranular and transgranular cracking.

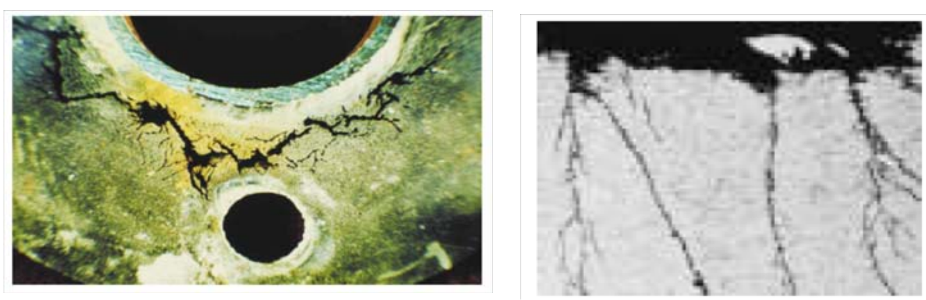


Figure 2.12 Intergranular Cracking and Transgranular Cracking (micrographs and SEM images)
(Source: National Physical Laboratory)

2.1.7 De-Alloying Cleavage

"De-alloying" is the removal of one element from an alloy by a corrosive process. Examples of this are graphitization (removal of iron) in gray cast iron and de-zincification, removal of zinc from brass containing more than 15 percent zinc. This de-alloyed layer is brittle. If the base material is ductile and is coated by its brittle de-alloyed layer, then a crack initiated by stress in the de-alloyed film could propagate into the ductile material even if only for a small distance before being arrested. The process of de-alloying, cracking, and crack arrest can repeat itself many times leading to a cleavage. Eventually, catastrophic cracking failure occurs.

2.1.8 Velocity-Related Corrosion

Perhaps the only form of corrosion exclusively associated with internal corrosion is velocity-related. The effect of the flow rate of fluid on the relative corrosion rate is depicted on Figure 2.13.

Flow-related effects includes erosion, erosion-corrosion, impingement, and cavitation. Erosion is the progressive loss of material from a solid surface due to mechanical interaction between that surface and a high-velocity fluid, a multi-component fluid, or solid particles entrained with the fluid. It is simply an abrasive metal loss; a physical rather than a chemical phenomenon. For erosion-corrosion to occur, the protective film of the metal is first removed by erosion exposing the underlying material to chemical attack, which is corrosion. Hence, erosion-corrosion is a conjoint action involving corrosion and erosion in the presence of a moving corrosive fluid or a material moving through the fluid, leading to accelerated loss of material. Erosion-corrosion normally exhibits a directional pattern and is characterized by grooves, gullies, waves, and round holes or valleys on the pipe's inside surface as depicted in Figure 2.14.

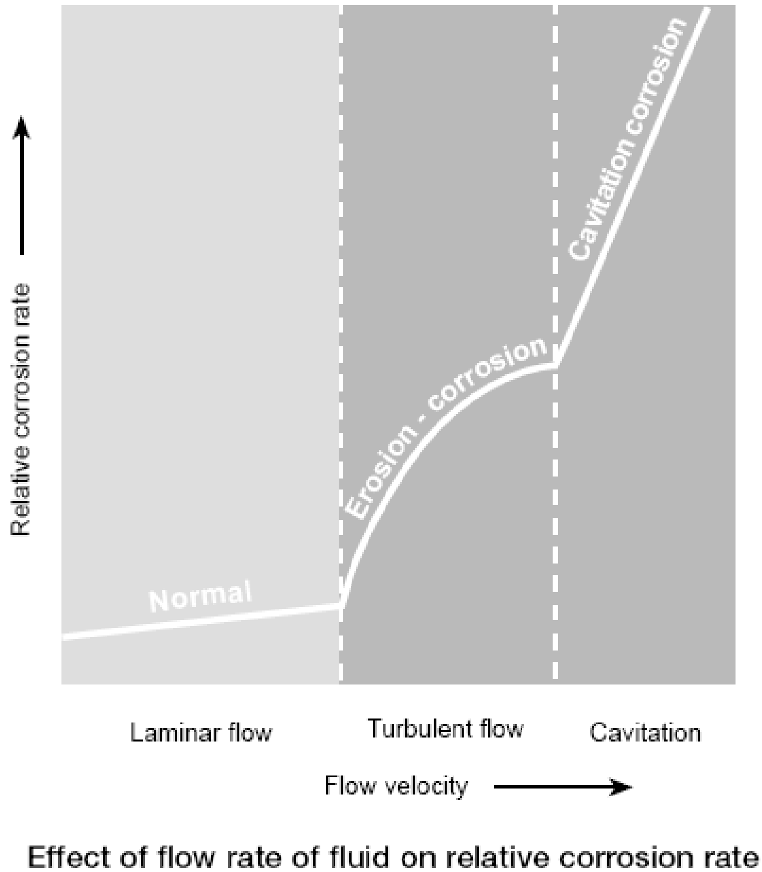


Figure 2.13 Effect of Flow Rate of Fluid on Relative Corrosion Rate
(Source: National Physical Laboratory).

Similar to erosion, impingement and cavitation are physical phenomena. An impingement event would entail the collision of a high velocity stream, with entrained particles and bubbles, on a metal surface at an elbow resulting in turbulence and damage to the protective film. The physical damage is normally elongated and undercut at the downstream end as depicted by Figure 2.15. The impingement process now exposes the underlying material to chemical attack. Hence, impingement corrosion could be simply described as a localized erosion-corrosion generally associated with the local impingement of a high-velocity, flowing fluid against a solid surface.

Figure 2.14 Grooves, Gullies, Waves, or Valleys Associated With Erosion-corrosion

Figure 2.15 Example of a Local Impingement Attack in High-Velocity Flow

Cavitation is the formation and rapid collapse of cavities and bubbles because of the momentary occurrence of low pressure occasioned whenever the absolute pressure at a point in a liquid stream is reduced to the vapor pressure of the fluid. Cavitation often results in damage to a material at the solid/liquid interface under conditions of severe turbulent flow. As the bubbles collapse, the surrounding liquid surfaces meet, releasing a significant enough kinetic energy to cause mechanical damage and/or break the protective film on the metal. The cavitation process now exposes the underlying material to chemical attack. This phenomenon occurs in pipelines when the oilfield fluid is moving at a high velocity.

Table 2.2: A Summary of Selected Forms of Corrosion

	Corrosion Type	Definition	Characteristics
1	Uniform or general corrosion	Corrosion that is distributed more or less uniformly over the surface of a material	• Shifting Anodic and Cathodic areas • Can occur in isolated locations along pipeline, but damage is uniform within the isolated location • General roughening
2	Localized corrosion	**Pitting Corrosion**: localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits **Crevice Corrosion:** localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment because of close proximity of the metal to the surface of another material	**Pitting Corrosion** • Deep narrow attack • Rapid penetration • Surrounded by non-corroded region • Has unique statistical distribution **Crevice Corrosion** • Localized attack that occurs in areas where access to surrounding environment is restricted • Occurs in metal-to-metal crevice • Occurs in metal-to-nonmetal crevice • Contains deposits of debris or corrosion products
3	Galvanic corrosion	Accelerated corrosion of a metal because of an electrical contact with a more noble metallic or nonmetallic conductor in a corrosive electrolyte	• This is a classical electrochemical cell • Occurs with metal-to-metal contact • Occurs with metal-to-active-nonmetal contact • Occurs with metal ion deposits • Occurs when there is electrical contact • Occurs when immersed in electrolyte
4	Microbiologically influenced corrosion	The degradation of a metal due to the metabolic processes and by-products of microorganisms	• Interface between metal surface and the organisms can be physically and chemically altered • Microbes break down passive pipeline film and accelerate corrosive attack • Microbial communities can create biofilms
5	Environmentally assisted cracking (EAC)	The key forms of EAC include (1) hydrogen induced cracking (HIC); (2) hydrogen embrittlement (HE); and (3) stress corrosion cracking (SCC)	• Can occur rapidly and results in catastrophic failures • Requires the combination of tensile strength and specific environment • There are different mechanisms for different forms of EAC.
6	Intergranular corrosion	Occurs as a result of impurities or precipitates accumulating at the grain boundaries resulting in a local corrosion cell at the grain boundary.	• Corrosion attack occurs at grain boundaries • It results in the depletion of an alloying component at the grain boundary leading to the setup of a corrosion cell • When a heat affected zone is adjacent to a grain boundary in stainless steel, it results in the formation of chromium carbide at the boundary

Table 2.2: A Summary of Selected Forms of Corrosion

	Corrosion Type	Definition	Characteristics
7	De-Alloying Cleavage	This is the removal of one element from an alloy by a de-alloying corrosive process	• The de-alloyed layer is brittle • If the base material is ductile and is coated by its brittle de-alloyed layer, then a crack initiated by stress in the de-alloyed film could propagate into the ductile material • The process of de-alloying, cracking, and crack arrest can repeat itself many times leading to a cleavage.
8	Velocity-related corrosion	Occurs as a result of metal loss caused by high surface fluid velocities. The three distinct types of velocity-related phenomena are (1) erosion-corrosion; (2) impingement corrosion; (3) cavitation corrosion	**Erosion-corrosion** • Removal of protective films • Accompanied with velocity and turbulence • Accompanied with mechanical erosion particles • Occurs with or without particles • Is identified with a break-away velocity **Impingement corrosion** • Localized erosion-corrosion caused by turbulence or impingement flow • It is characterized with directional features • It is accelerated by entrained gas or solids • It is also associated with liquid drop impingement **Cavitation corrosion** • Mechanical damage from collapse of bubbles in a liquid • Causes the removal of protective film • Causes direct mechanical damage to pipeline

2.2 Overview of Corrosion Control Methods

There are six key corrosion control methods that are generally classified under the following headings:

- materials selection
- protective coatings
- cathodic protection (CP)
- electrical isolation
- environmental control (or alteration of the environment)
- design.

These control methods are often used in conjunction with one another to achieve a desired level of synergism. For example, protective coatings are used to minimize the current requirements in cathodic protection; zinc metal, a CP sacrificial anode, is used as a pigment in protective coatings; passivating inhibitors are used with corrosion resistant alloys; and intelligent/scraper pigging are periodically used in lines that are chemically treated to control internal pipeline environments.

2.2.1 Material Selection

Material selection for corrosion control is a complex economic and technical decision involving the consideration of lifecycle cost, construction practices, and operating procedures. The selection of a specific alloy for a particular application is important; so is the selection of an appropriate fabrication method (such as welding or cladding) that would not impair the final properties of the carefully selected material. The right choice is essential for long-term corrosion control and for an optimum balance between capital expenditure (CAPEX) and operating expenditure (OPEX) that would maximize the quality, integrity, and operating safety of the pipeline. The use of corrosion allowance is perhaps the simplest illustration of the interplay of economic and technical considerations in material selection.

Generally, short pipeline sections and a long expected lifetime normally favor the choice of more expensive corrosion-resistant alloys (CRA) with significantly reduced operating costs. An extensive pipeline system normally favors the use of less expensive material with significantly high operating costs including the use of additional corrosion control methods such as chemical treatments, coatings, and/or cathodic protection.

The choice of a corrosion resistant material for a particular application depends on the expected service conditions. For example, the susceptibility of metallic materials to cracking in H_2S (sour) service depends on; H_2S partial pressure, in situ pH, the concentration of dissolved chloride or other halides, the presence of elemental sulfur or other oxidant, temperature, galvanic effects, mechanical stress, and time of exposure in contact with liquid water phase. Detailed information on material selection for corrosion control in sour service is available in NACE MR0175 and NACE MR0103.

For example, NACE MR0175 recommends that carbon steel may be used in sour service provided the H_2S partial pressure is less than 0.05 psia (0.0003 MPa). Other major petroleum exploration and production companies adopt a limit of 2 ppm H_2S. Still others advocate the use carbon steels with yield strength of less than 90,000 psi in H_2S environment to prevent the possibility of hydrogen-induced cracking.

Material selection for pitting corrosion control is also important for carbon dioxide (sweet) corrosion and oxygen-assisted corrosion.

Table 2.3 presents a general classification of materials selection for corrosion control. Commercial softwares are available for the selection of appropriate corrosion resistant alloys and they incorporate (1) critical design parameters; (2) material requirements per NACE MR0175 guidelines; (3) material requirements per NACE MR0103 guidelines; (4) other available guidelines; and (5) other available material selection databases. The majority of oil field equipment is constructed of steel; carbon steel, low-alloy steel, austenitic steel, duplex (austenitic/ferritic) stainless steel, ferritic steel, martensitic steel and stainless steel.

Table 2.3: Material Selection for Corrosion Control

Metals		**Non-Metals**	
Ferrous Alloys	**Nonferrous Alloys**	**Plastics**	**Cementitious Materials**
Carbon and alloy steels	Nickel-based alloys	Thermosetting composites	Cement and concrete
Stainless steels	Copper-based alloys	Thermoplastics	Cement asbestos
Cast irons	Aluminum and aluminum alloys	Elatomers	Ceramic tile
Iron-Nickel-chromium alloys	Titanium and titanium alloys		

2.2.2 Protective Coatings

Probably the most practical and straightforward means of corrosion control involves finishing pipeline surfaces with appropriate protective coatings. Coatings are believed to be the first line of defense in corrosion control. Coatings used for corrosion prevention fall into the following main categories:

1. Sacrificial coatings
2. Inhibitive coatings
3. Conductive coatings
4. Barrier coatings

2.2.2.1 Sacrificial Coatings

Sacrificial coatings are normally primers whose pigment is rich in zinc or pure metal that has excellent galvanizing, metallizing, or plating characteristics. In contact with carbon steel substrate, the pigments act as sacrificial anodes providing cathodic protection to the substrate and producing alkaline corrosion products that passivate the underlying steel substrate. The pigment also fills voids normally present in the top coat preventing the ingress of water or oxygen to the substrate surface. The performance of these types of coatings is dependent upon the substrate surface preparation; the pigment degradation rate, the primer film thickness as well as the prevailing environment.

2.2.2.2 Inhibitive Coatings

The functional behavior of solvent-borne inhibitive coatings is similar to that of the sacrificial coatings except that the active pigments (e.g., red lead, zinc chromate) are soluble in the carrier solvent. On application, the solvent evaporates and the pigment coats and passivates the steel substrate. For environmental protection reasons, the soluble pigments are regulated substances whose concentration in the atmosphere is generally limited by law. Hence, inhibitive coatings are not widely used.

2.2.2.3 Conductive Coatings

Inherently conducting polymers (ICP) are emerging as noble passivating coatings for iron, steel, aluminum, copper or zinc. Such polymers, called organic metals, include polyaniline, polypyrrole, and polythiophene. Polyaniline has been the polymer of choice for the available coatings. The two passivating mechanisms of conducting polymeric coating systems are said to be complementary. Because their normal potential is close to that of silver, the coatings would ennoble the surface of the metal being protected by shifting its corrosion potential by up to 800 mV making it more difficult for corrosion to start. In addition, the coatings catalyze the formation of passivating metal oxide surface layers such as Fe_2O_3, Al_2O_3, CuO depending on the metal being coated. Like the self-protecting oxide forming mechanism of aluminum, the oxide layer is passive relative to the corrosive media and it constitutes a physico-chemical barrier that is resistant to corrosion attack. Combined, the dual mechanisms are said to be able to reduce corrosion rate by a factor up to several thousands.

An advantage offered by this emerging coating system is its ability to tolerate pin holes and scratches in carbon steel. The conductivity of the ICP coatings enables the passivation of any exposed metal including pinholes and scratches. Indeed, recent studies have confirmed the potential of ICP to provide long-term corrosion protection to buried carbon steel pipelines through passivation.

2.2.2.4 Barrier (Dielectric) Coatings

The most commonly used coatings for energy pipelines are barrier (dielectric) coatings, which provide a “barrier” between carbon steel components and the corrosive environment. They generally impede the diffusion of oxygen and water to the pipe surface and restrict contact with electrolytes. The following are the desirable characteristics of barrier coatings:

- Ease of application
- Ease of repair
- Resistance to disbonding
- Good adhesion to substrate surface
- Ability to provide electrical insulation
- Ability to provide moisture barrier
- Ability to resist development of holidays over time

- Ability to withstand normal handling, storage, and installation
- Ability to maintain substantially constant electrical resistivity with time
- Nontoxic interaction with the environment

From the historical viewpoint, coatings have been used for corrosion prevention of oil and gas pipelines since the early 1900s. The chronological evolution of common coating types is presented in Table 2.4, which also illustrates the advantages and disadvantages of each class of coatings.

Over the years, various polymeric coatings have protected pipelines. In the 1940s and 1960s, coal tar or asphalt coatings were applied. In the mid-1950s, mill-applied extruded polyethylene coatings were introduced (primarily on small-diameter pipes). From the early 1960s to the early 1980s, polyethylene tape coatings were field applied.

Asphalt and coal tar enamel, polyethylene tape coating; extruded polyolefin (polyethylene for ambient temperature and polypropylene for high temperature service), and fusion bonded epoxy (FBE) are unable to withstand the high temperatures of some buried oil pipelines and gas flowlines operating at temperatures up to 250^{o}F (121^{o}C) for prolonged periods. These high temperatures cause degradation of the traditional coatings leading to bare areas, which are susceptible to corrosion.

Table 2.4: Chronological Evolution of Common Coating Types

Coating Type	Chronology	Advantages	Disadvantages
Asphalt and Coal Tar	1910-Present	Easy to apply	Subject to oxidation and cracking
		Minimal surface preparation required	Soil stress has been an issue
		Long track record in certain environments without failure	Limitations at low application temperatures
		Permeable to cathodic protection in event of failure	Environmental and exposure concerns
			Associated with corrosion and stress crack corrosion failures
Tape Wrap (2-layer)	1950-Present	Simple application	Poor shear stress resistance
			Many documented failures related to corrosion and stress crack corrosion
			Shielding of cathodic protection
			Adhesives subject to biodegradation
2-Layer Extruded Polyethylene	1960-Present	Excellent track record	Limited temperature range
		Good handling	Poor shear stress resistance
			Limited pipe sizes (<24 in. [610 mm] outside diameter)
Fusion-Bonded Epoxy	1975-Present	Excellent adhesion and corrosion resistance	Low impact resistance
		Does not shield cathodic protection – Fail safe coating	High moisture absorption and permeation
3-Layer Polyethylene	1986-Present	Excellent combination of properties	Best suited for electrical resistance welded pipes
Multi-layer or Composite Coatings	1990-Present	Excellent combination of properties; Conforms well to external raised weld profiles	High thickness to eliminate weld tenting
			Suitable only for large diameter pipes and is not designed for small diameter pipes (<406 mm OD)

The 3-layer polypropylene coating withstands temperatures as high as 230^oF (110^oC) and eliminates the need for coating renovation at intervals normally recommended for traditional FBE coating.

The 3-layer polypropylene has a respectable field performance record with major exploration and producing companies in the following locations; Oman, UAE, Saudi Arabia, Egypt, Syria, Nigeria, Angola, Thailand, Argentina, Ecuador, Venezuela, Columbia, Norway, Germany, France, and Italy. The schematic image of a 3-layer polypropylene coating is presented in Figure 2.16.

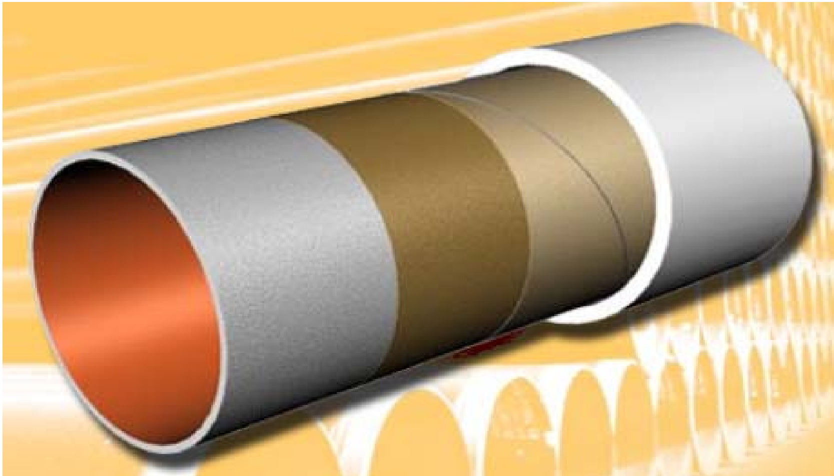


Figure 2.16 Schematic Image of a 3-Layer Polypropylene Coatings

Multi-layer or composite coatings usually consist of an FBE inner layer on the pipe surface and a polyethylene or polypropylene outer layer with an adhesive material between the inner coating and the outer wrapping. A high resistance to disbondment, mechanical damage, soil chemistry and other stresses characterizes this relatively new coating technology. The major drawback relates to the fact that the polyolefin outer layer would shield CP current if disbondment occurs.

2.2.3 Cathodic Protection

Cathodic protection is fundamental to preserving pipeline integrity through corrosion control. Cathodic protection (CP) controls corrosion first by eliminating the potential differences between the anodes and the cathodes on the corroding metal structure and second, by creating a negative potential difference between the CP anode and the corroding metal structure thereby making the corroding structures the cathode of a new electrochemical cell. In essence, CP is the technique used to control the corrosion of a metal surface by making that surface the cathode. There are basically two types of cathodic protection systems; the sacrificial (Galvanic) anode system and the impressed current cathodic protection (ICCP) system. Cathodic protection is defined as the reduction or elimination of corrosion by means of an attachment to a sacrificial anode or through an ICCP.

In the first, the current derives from the galvanic couple set-up between the sacrificial anodes and the structure to be protected. In the second, the current is supplied (impressed) from an external direct current (DC) power source via relatively inert anodes. ICCP simply introduces DC protective current into the structure to be protected. In general, some of the conditions that determine which type of CP system to use appear in Table 2.5.

Table 2.5: Galvanic Anodes Versus ICCP Anodes

Sacrificial Anodes		ICCP Anodes
1	Current requirements are low	Current requirements are high
2	Soil resistivity is low (<10,000 ohm-cm)	Soil resistivity is high (>10,000 ohm-cm)
3	Electrical power is not available	Electrical power is readily available
4	Relatively limited lifetime protection	Long life protection is required

2.2.3.1 Components of Galvanic CP

There are four basic components of a galvanic anode CP: (1) the anode, (2) the anode backfill, (3) a means of connecting the anode to the structure, (4) and the structure (Figure 2.17).

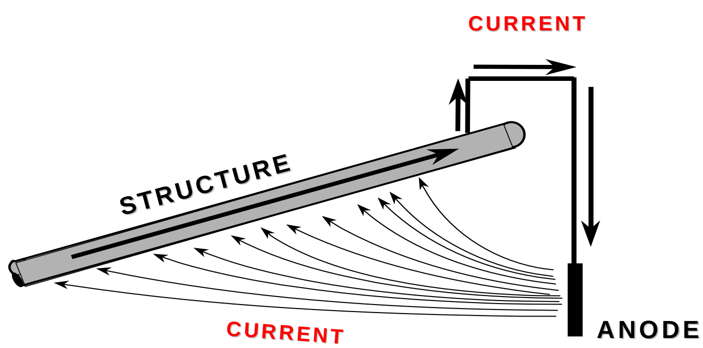


Figure 2.17 Typical Galvanic Anode Cathodic Protection

Anodes: Galvanic CP operates on the principle that a more active metal connected to a less active material will form a galvanic corrosion cell. This is used to protect the less active metal. The more active alloy will corrode ("sacrifice" itself) to protect the protected metal. This is why these anodes are often called *sacrificial anodes* (Figure 2.18).

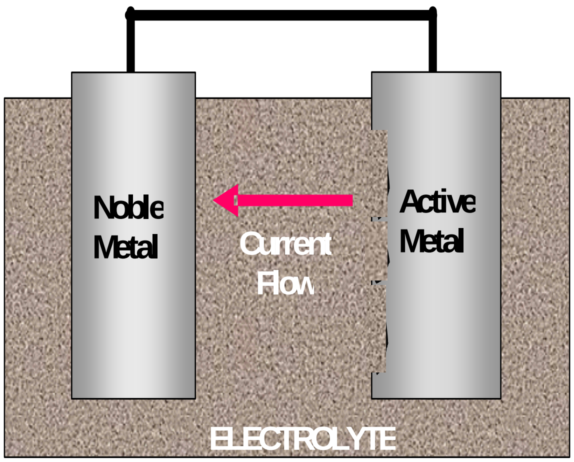


Figure 2.18 Galvanic Corrosion Cell

The practical galvanic series of metals (shown in Table 2.6) shows three metals more active than the iron to magnesium range, zinc, and aluminum. (Note: a complete EMF or galvanic series table will show other metals more active than iron, but these three are the most useful.) The most common active metals used as anodes to protect iron alloys, copper, and lead are alloys of magnesium, zinc, and aluminum.

Alloys of magnesium, zinc, and aluminum are the most widely used sacrificial anode CP systems and have been developed to enable the anode to remain active and extend the life of the cathode. The pure forms of the metals are often not suitable as anodes because they undergo too much "self corrosion" in the environment and do not stay active. In general, the consumption rate per ampere per year of these alloys are: magnesium 7.7 kg (17 lbs.), aluminum 3.1 kg (6.8 lbs), and zinc 12.7 (26 lbs). Because of its high driving potential, magnesium anodes are widely used in soil applications, or fresh or condensed water in vessels. Because of its high energy capability per kilogram of anode, aluminum finds extensive application in seawater and brines. Zinc finds application in low resistivity soils and water. A striking disadvantage of zinc is its ability to reverse polarity, becoming cathodic to steel, depending on temperature (65^0C), presence of dissolved ions, pH, and immersion time. The necessary condition for such reversal has also been linked to the passivation of the zinc surface and the presence of dissolved oxygen that provides cathodic depolarization in water.

The design and installation of galvanic anode systems depends on the application and the expected design life. For water handling applications in tanks and vessels, blocks, slabs or spherical anodes may be used. For underground applications, the anodes are predominantly cylindrical, constructed of magnesium or zinc and are usually bare or prepackaged with backfill material. The buried or submerged anodes are installed near the pipeline and connected to the pipe with an insulated conductor. The cathodic protection electrochemical cell so created induces the flow of ionic current through the earth to the pipeline. The ionic current is proportional to the potential difference between the two metals and the anodes are sized to deliver the required protective current over the desired design life of the CP.

Galvanic CP is applicable in oil and gas gathering centers and distribution systems. They are also used for internal corrosion mitigation of surface equipment and vessels for produced brines, oil storage tanks, production and salt water disposal tanks, accumulators, separators, etc. For tanks and vessels, it is particularly important to note that CP provides protection ONLY in the line of sight of the anode.

Table 2.6: Practical Galvanic Series in Seawater

Metal	Volts vs. Cu-$CuSO_4$	Volts vs. Ag-AgCl
	Active or Anodic End	Active or Anodic End
Magnesium	– 1.60 to –1.75	– 1.55 to –1.70
Zinc	– 1.10	– 1.05
Aluminum	– 1.05	– 1.00
Clean Carbon Steel	– 0.50 to –0.80	– 0.45 to –0.75
Rusted Carbon Steel	– 0.30 to –0.50	– 0.25 to –0.45
Cast/Ductile Iron	– 0.50	– 0.45
Lead	– 0.50	– 0.45

Steel in Concrete	– 0.20	– 0.15
Copper	– 0.20	– 0.15
High Silicon Iron	– 0.20	– 0.15
Carbon, Graphite	+0.30	+ 0.35
	Noble or Cathodic End	Noble or Cathodic End

2.2.3.2 Components of Impressed Current CP

The components of an impressed current CP system are anodes, anode backfill, a power supply (rectifier), structure, wiring, and connections. The anodes used in impressed current CP systems are different from those used in galvanic systems. Impressed current anodes are manufactured from materials that are consumed at low rates. Impressed current CP systems generally operate at higher current and driving voltage levels than galvanic anode CP systems.

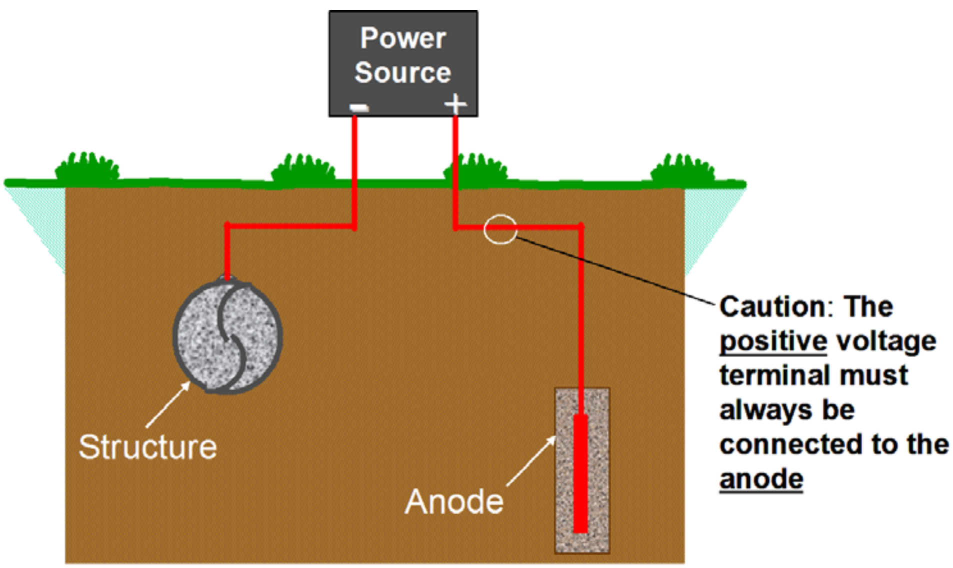


Figure 2.19 Typical Impressed Current Cathodic Protection

Rarely is ICCP used to protect the interior of pipelines. Its typical applications are:

- For large current requirements, particularly for bare or poorly coated structures
- In all electrolyte resistivities

- As an economical way of protecting structures having dissipated galvanic anodes
- To overcome stray current or cathodic interference problems
- For protection of large heat exchanger water boxes, oil heater-treaters, and other vessels
- For interiors of water storage tanks
- For exterior bottoms (both primary and secondary) of above ground storage tanks
- For underground storage tanks
- For underwater components of offshore structures
- For foundation piles and sheet piling, both underground and in the water

Anodes: For oil and gas transmission pipelines, buried flowlines, well casings, and injection lines, cathodic protection is most often applied in the form of impressed current systems where a single installation can protect miles of pipe. There are a variety of ICCP anodes consisting of metallic materials, non-metallic materials, metallic oxides and mixed metal oxides. In this case, anodes are constructed of relatively inert ground electrodes made of mixed metal oxide or platinum-coated titanium, high-silicon-chromium cast iron, or graphite. The anodes are connected to a transformer-rectifier (T/R) unit that steps down AC line voltage and rectifies the AC to DC. The DC current induces the flow of the protective ionic current through the earth to the surface of the pipe (Figure 2.19).

Coating plays an integral role in the proper functioning of a pipeline cathodic protection system. When using CP with dielectric pipe coating, the current from the CP ground bed is reduced by the effectiveness of the coating system. CP current needs only to protect the pipe at holidays (defects) in the coatings where the steel substrate is exposed to the soil or water. There is no such thing as a perfect protective coating; holidays (or holes in the coating) do exist on all coated surfaces due to a variety of causes such as damage, deterioration, or microscopic pinholes associated with imperfect application. This is illustrated in Figure 2.20.

Figure 2.20 Rapid Penetration of Pipe Wall at Coating Defect

Although it is true that coatings are the first line of defense for a carbon steel pipeline, with few exceptions all coatings have holidays which can allow corrosion of the pipeline. Only in a few very limited cases can a coating be expected to be free of holidays. As a result, CP is often used to provide supplemental protection of the pipeline, primarily to protect metal at holidays in the coating. The coating effectively separates most of the metallic surface from direct contact with the environment. This leaves only small damaged areas (holidays) in the coating for the cathodic protection system to protect. The amount of cathodic protection current required to protect a coated structure immersed in an electrolyte is directly related to the amount of coating damage (bare surface area) and quality of the coating on the structure. As coatings age with exposure to electrolytes, the coating gradually degrades and the equivalent bare surface area requiring protection increases. Prior to the emergence of FBE and other strong adhesion coatings in late 1970s, a typical design factor for coating holidays was less than 5% bare area for a pipeline coating. The coatings of today typically have far less CP current requirements.

Coatings could deteriorate to the point of total ineffectiveness of CP for mastics, asphalt enamels, coal tar enamels, and tapes (caused by disbondment). The role of protective coatings in conjunction with cathodic protection is to extend the useful life of buried or submerged equipment. Pipelines normally represent large capital investments. Often replacement costs as a result of corrosion can far exceed the original costs. Typically, the cost to replace a small section of pipeline is more expensive than the initial installation costs. Mobilizing equipment and labor, transporting materials, and excavation and replacement of small sections of pipeline are much more costly. However, rehabilitation of pipeline coatings, for example, often cost more than the cost for the original coating and may even justify pipeline replacement instead of rehabilitation.

Pipelines are normally protected by a combination of coatings and cathodic protection. Most buried or submerged structures are initially coated with a high quality dielectric protective coating to mitigate corrosion. Dielectric protective coatings often perform the greatest percentage of corrosion control on structures exposed to corrosive environments. High dielectric organic coatings greatly reduce the total current requirements for a cathodic protection system. High dielectric coatings also help to mitigate attenuation on long pipelines and improve current distribution. As coatings age, the current leakage through holidays and moisture absorption increases and this in turn increases current attenuation. On long pipelines in very conductive environments (e.g., seawater), the dielectric properties of the coating have a significant impact on attenuation. Coatings with poor dielectric properties have greater attenuation. Generally, coatings with poor dielectric properties will require significantly greater cathodic protection current output to achieve corrosion control.

2.2.3.3 Cathodic Protection Effectiveness

Various techniques may be used to determine the degree to which a structure under cathodic protection (CP) is actually protected against corrosion, including:

- Structure-to-electrolyte potential
- Test coupons
- Current measurements
- Surface potential measurements
- Soil resistivity
- Direct observation
- Leak frequency

- In-line inspection

Potential measurements are a common means for determining if adequate protection has been achieved. With the application of current through the environment onto a structure, a potential change with respect to the environment will occur. The potential change also includes polarization; the change from the open circuit potential as a result of current across the electrode/electrolyte interface. To ensure that adequate cathodic protection has been achieved, potential measurements should be made to determine whether one of the cathodic protection criteria has been met. According to the NACE SP0169, the three key CP criteria are as follows:

- A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte.
- A negative (cathodic) polarized potential of at least 850 mV relative to a saturated copper/copper sulfate reference electrode; the polarized potential being the potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization
- A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be used to satisfy this criterion.

For the first criterion, voltage drops other than across the structure-to-electrolyte boundary must be considered. For bare pipelines, the effects of voltage drop both in the soil and in the metal are important considerations and several methods are available for assessing voltage drops. The first and the second criteria are more appropriate for use on coated pipes and the third is more appropriate for use on bare pipelines.

2.2.3.4 Cathodic Protection Versus Coating Rehabilitation

All coatings are subject to gradual deterioration as a function of time depending on the coating quality and the general corrosivity of the environment. Fusion-bonded epoxy (FBE) coatings have dominated the post 1980s pipeline coating industry and most natural gas pipelines installed after the eighties were coated with FBE coating. Many natural gas pipelines do experience serious temperature induced coating failures. The high service temperatures of these pipelines, exceeding 220°F (104°C), severely damage the FBE coatings after approximately five years in service. For deteriorating coatings, the CP systems, installed during the original construction of the pipelines, are normally designed to protect coating holidays of less than 5% of the total surface area of the pipeline. Because of this, the CP system becomes inadequate and ineffective when external coatings of the buried pipelines degrade beyond a certain degree, significantly above 5% of the total surface area.

Performance tests are useful to evaluate the rate of coating deterioration at intervals during the operating life of a coated pipeline. To ensure adequate CP protection, field experience indicates that the FBE coated pipelines, with temperature-induced coating failures, would require complete coating renovation approximately every four years. Such FBE coatings, normally applied in the plant, are impractical for coating rehabilitation in the field. Liquid coating systems are normally utilized. In addition, coating rehabilitation of badly damaged FBE coated pipelines is very expensive, given the expenditures for mobilization, excavation, removal of the old coating, and the application of the new epoxy-based liquid coating system.

On the other hand, no coating renovation is required if a flexible linear anode CP system is used as it is able to provide adequate cathodic protection to buried pipelines with severe coating damage. The use of linear anode CP systems and/or distributed groundbeds instead of complete coating rehabilitation of the pipelines with severely damaged FBE coatings results in savings of about 50% of the cost for a one-time coating rehabilitation. Hence, a flexible linear anode CP system represents an alternative to FBE pipeline coatings rehabilitation because of its cost-effectiveness compared to re-coating; considerable cost savings could accrue from the use of this CP system in rehabilitating old structurally sound pipelines with severely damaged coatings.

Flexible linear anode CP systems are characterized by the following unique advantages when compared with the conventional remote ICCP systems:

- Better current distribution
- Minimal hydrogen over-voltage
- Reduced risk of cathodic disbondment
- Reduced CP interference
- Reduced CP current requirement

2.2.4 Electrical Isolation

Another practical means of corrosion control is to ensure the electrical isolation of structures that are susceptible to galvanic corrosion or interference current corrosion.

2.2.4.1 Dissimilar Metals

Pipeline system design should avoid the use of dissimilar metals in direct contact or through a common electrolyte. In cases where dissimilar metals are used, electrical isolation methods need to be applied to break up the metallic continuity and prevent or significantly reduce the galvanic corrosion that would ordinarily result.

Examples of this sort of occurrence of dissimilar metals are as follows:

- Electrical grounding
- Mixing of carbon and stainless steel tubing, fittings or brackets
- Contact of metals and non-metallic conductors such as graphite or carbon black
- Stainless steel piping connected to the nozzle of a coated vessel
- Stainless steel internals in an internally coated vessel

Table 2.6 illustrates a typical order of the potential of selected alloys, reflecting their propensity to corrode when they are in contact. If dissimilar metals are used, the more electronegative metals (higher in the series) will be anodic and therefore corrode when coupled to the more electropositive metals (lower in the series). In cases where dissimilar metal contact cannot be avoided, the materials having nearly similar potential should be selected to reduce the electrochemical driving force for corrosion.

The difference in potential between the metals is an indication of the driving force of the corrosion cell and the relative areas of direct contact or direct exposure to a common electrolyte will influence the corrosion intensity. In this regard, the corrosion process will be under cathodic control. Hence, if dissimilar metals must be used, the design should seek to minimize the area of the cathode relative to that of the anode to minimize the corrosion intensity. This could also be accomplished by coating the cathode. Other tenable options to minimize galvanic corrosion could involve the use of inhibitors or the introduction of an environment free of electrolytes.

2.2.4.2 Stray Current or Interference Current

Stray current is not the galvanic corrosion current between anodes and cathodes on the same structure. The current that passes through electrical paths other than the intended circuit is classified as stray current; it could be static or dynamic, alternating or direct current. DC stray current causes significant corrosion of most metals. In this case, stray current corrosion could be caused by systems such as DC transit systems, DC mining operations, electrical grounding rods, grounded cathodic protection systems for adjacent buried pipelines, DC welding operations, high voltage DC transmission systems, etc. AC stray current is more of a safety hazard than a corrosion problem. The exception is that AC can cause significant corrosion of aluminum.

Stray current is especially damaging because large currents, often involving many amperes, might be involved. On the other hand, even small amounts of stray currents can be highly damaging if discharged over a small surface area. In some areas, particularly around older rail rapid-transit systems or in the vicinity of underground mine railroads, pipelines may carry hundreds of amperes of stray current. For every ampere discharged from a structure, a certain amount of metal is lost. Faraday's Law allows us to relate the corrosion lost to the amount of current discharged. For ferrous metals (cast iron, ductile iron, steel), copper, and lead the loss rates are:

Ferrous	20 pounds / A-yr (9.1 Kg / A-yr)
Copper	23 pounds / A-yr (10.4 Kg / A-yr)
Lead	74.64 pounds / A-yr (33.85 Kg / A-yr)

If not controlled, stray current can destroy a structure very rapidly or at least to a potentially catastrophic situation. Depending on the stray current density at penetration, steel structures in environments that normally would not be considered corrosive could experience accelerated corrosion when exposed to stray current conditions. Stray current, being from an external source, enters the pipe or other structure through the soil (or other electrolyte). Except for some amphoteric metals such as aluminum and lead that suffer “cathodic corrosion” in stray current “pick up” areas, stray current normally does not cause corrosion at the entry point for other metals. On the contrary, many structures receive “free” cathodic protection from stray currents at the point of entry. The damaging effect of stray current typically occurs if the current *leaves* the structure through the electrolyte where corrosion would be accelerated.

2.2.5 Environmental Control

Environments in exploration and production systems are often modified to control corrosion. The environmental control variables include pressure, temperature, flow dynamics, the overall stress state of the pipeline, and the internal and external environment. Pressure and temperature control affect the state of stress on the pipeline. Temperature also has a far more important effect on corrosion reaction rate. The rule of thumb for any chemical reaction, including the rate of corrosion, is that the reaction rate doubles for every 10-degree Celsius rise in temperature. On the other hand, the solubility of dissolved acid gases such as H_2S and CO_2 decreases with increasing temperature and their complete removal would considerably reduce corrosion concerns. Processes such as dehydration and de-aeration serve the purpose of altering the environment to affect corrosion control.

The key to environmental control is to alter an essentially corrosive environment by chemical treatment, adjusting the conductivity of the environment, particularly the pH, or ensuring that the environment is “insulated” from potential corrosive elements.

Bedding and backfill are examples of altering the environment of a buried pipeline as they protect the coatings on the pipeline and minimize potential installation stresses. They do not, however, permanently alter the electrochemical properties of the electrolytes.

2.2.5.1 Chemical Treatments

Chemical treatment of pipelines with corrosion inhibitors, oxygen scavengers, and biocides is perhaps the most important environmental control methodology in exploration and production.

Corrosion inhibitors mitigate corrosion by adsorbing to metal surfaces. Note, however, that some corrosion inhibitors and carriers such as alcohols may serve as a food source to some bacteria and may actually promote their growth. Therefore, an effective corrosion inhibitor program requires the selection of the proper inhibitor for the operational characteristics of the system. Chemical treatment with surfactants or dispersants may be required for systems fouled with biofilms and/or solids. Pigging may also be required. Accumulated solids may result in under-deposit corrosion and create an environment favorable for localized attack, including microbiologically influenced corrosion (MIC).

To effectively control MIC, biocides are generally targeted at the original source of the microbes rather than the complete system. All sources of liquids should be evaluated in order to detect the presence of bacteria and determine whether MIC is a possibility. It has also been established, however, that the presence of bacteria alone does not indicate that MIC is occurring. Nonetheless, bacteria and oxygen exclusion must be rigorous.

Oxygen scavengers are a poor second choice relative to oxygen exclusion. In any closed loop system such as a firewater system, oxygen content should not be more than ten parts per billion and an excess oxygen scavenger should always be maintained in the system. In general, the oxygen scavenger must be maintained at ten times the oxygen content in the system. Wash water and seawater treatment plants should be treated with oxygen scavengers, biocide, and corrosion inhibitors, but not at the same injection point. Corrosion inhibitors normally work in an oxygen-free environment. Hence, corrosion inhibitors may be injected at a location about ten pipeline diameter-lengths from the location where the oxygen scavenger is injected.

When a new chemical is being considered, it is recommended that the vendor supply the following:

- Material safety data sheet (MSDS)

- Technical data sheet
- Temperature stability (ambient to maximum of 180°F [82°C])
- Compatibility information (corrosivity toward steels, sealing materials and other treatment chemicals [e.g., biocides]) and/or test results and case histories
- Performance testing
- Corrosion inhibitor partitioning, corrosion testing (e.g., flow loop, autoclave, and/or others as applicable)
- Biocide kill test results (sessile vs. planktonic)
- Complete price matrix

To ensure quality control, the following action steps should be followed:

1. Obtain a certificate of analysis (COA) for each shipment to verify that the product meets specifications.
2. Obtain a sample from the shipment and check some of the specifications to verify that they match the values listed on the COA.
3. Retain a sample of the shipment for future testing if you encounter problems with the product during use.

Several simple tests exist to ensure that each delivery is the same product that was initially specified. It is recommended that one or more of these tests be considered upon subsequent deliveries of the specified product. In order of complexity they are:

- Specific gravity (i.e., density)
- Appearance (e.g., color, sediment, phase separation)
- pH in 50% de-ionized [DI] water
- Grindout (e.g., ASTM D-96)
- IR major peak comparison
- Ultraviolet absorbance

Chemicals may be applied as a batch or continuously. The choice of an application method is a function of the type of inhibitor. Amine-type, film-forming inhibitors adsorb on the corrosion product layer and have varying degrees of film life. Other types of inhibitors interact chemically with the metal surface and have to be applied on a continuous basis.

Batch or slugs (large volumes injected at once): An example of slug (batch) treatment in a pipeline is when a measured amount of chemical is placed between two pigs to lay a film down on the circumference of the pipe wall. Batch treatments do not require maintenance of an injection pump. For a low water-cut hydrocarbon pipeline system, batch treatment can be effective with proper inhibitor selection because the polar inhibitor molecule will not dissolve in the dominant hydrocarbon phase and will be available to contact the water phase where the corrosion occurs. The inhibitor used in this situation should be formulated to have a high affinity for water and designed to partition strongly to the water phase. When very low levels of free liquids are transported with gas, batch treatment, either in the form of slugs or between pigs (conventional or sacrificial), is usually recommended to help deliver the chemical downstream. Sacrificial pigs are typically foam pigs that are not intended to be recovered intact after traveling through the pipeline. Batch treatments do not depend on partitioning because the inhibitor is delivered to the pipe through its own carrier.

Continuous Injection: With this method, a controlled dose is used to maintain a steady concentration of inhibitor. The performance of the system and the choice of application are largely based on the film persistence of the inhibitor. By definition, persistence is the ability of an inhibitor to resist detachment from the metal surface it protects. Some continuous injection inhibitors can display excellent film persistence under specific conditions. For other conditions, a batch treatment is more effective. When liquids are known to be transported, continuous injection of chemical is the recommended application method because the chemical is well distributed down the pipeline. Typical dosage concentrations range from 50 to 250 ppm (depending on corrosivity and chemical) in the desired liquid phase. If the product is water-dispersible (i.e., designed to prefer the water phase vs. the hydrocarbon phase), the injection rate should be based on the water volume. Continuous treatments ensure that treatment is uninterrupted and tend to use corrosion inhibitors designed to partition (e.g. move) into the water phase. Another option for under-saturated gas is to utilize a nonvolatile carrier (i.e., ethylene glycol) for continuous inhibition. Continuous application is used frequently in environments requiring a constant concentration of inhibitor residual in the liquid phase.

Most mitigation chemicals are soluble in either hydrocarbons and/or water liquids being transported. Typically, chemicals are recommended for injection at a concentration in parts per million (ppm). The appropriate amount of chemical to use may be determined by using the following equation:

$$\text{Gallons of chemical} = \frac{\text{42 gals/barrel x barrels x ppm treating rate}}{1{,}000{,}000}$$

The usefulness and efficiency of chemical treatment is affected by numerous conditions such as temperature, velocity, solubility, and compatibility with other chemicals.

Effect of Temperature: There is widespread agreement that the effectiveness of chemicals is usually adversely influenced by increases in temperature. The extent to which temperature affects chemical efficiency often can be determined only after tests in the actual corrosive medium and operating conditions are studied. In some cases, the maximum operating temperature limits for treating chemicals are well known. The temperature factor is always important and always a design consideration.

Effects of Velocity: The effects of velocity are important in inhibition, especially when considered in relation to performance. Performance of chemicals can be affected adversely by high velocity. On the other hand, performance of certain chemicals can be adversely affected by low velocity due to low solubility. It has been established that corrosion behavior and inhibitor performance are highly dependent on the chemistry and flow conditions in the pipelines. Flow conditions often determine film persistence and, therefore, dictate the method and chemistry of inhibition. Inhibitors should be selected based on the operating conditions under which internal corrosion actually occurs in the pipeline. Laboratory and field testing for inhibitor performance under simulated flow conditions are essential in order to optimize chemical use and protection of the pipe.

Solubility: All liquid corrosion inhibitor chemicals can be classified according to their water and oil solubility and dispersibility characteristics. These characteristics are important for several reasons. Many treating techniques call for diluting the chemical in a proper solvent (water, condensate, kerosene, etc.) before application. A chemical is generally considered soluble in a solvent if the chemical-solvent mixture remains clear. A chemical is considered dispersible in a solvent if it can be dispersed in the solvent by moderate hand shaking. The dispersion of the chemical in the solvent may separate rapidly or remain uniformly dispersed in the solvent for long periods of time. Depending on the chemical makeup of the solvent, the chemical may be partly soluble and partly dispersible in a specific solvent system.

Compatibility with other Chemicals: Compatibility of corrosion treatment chemicals with other products is ordinarily not a problem when two or more chemicals are present in concentrations of only a few ppm. However, in some cases, two or more chemicals will react with each other, nullifying their effectiveness or causing operational problems. The chemical user may want to mix various chemicals so that a single chemical pump can be used for injection. Many oilfield chemicals are not compatible with other products because of variations in the solvent system, the type of chemical, etc. Test the compatibility of chemicals prior to use.

2.2.5.2 Biocides

Biocides are mandatory when MIC is indicated. Biocides can be broadly classified into *oxidizers* and *non-oxidizers*. Oxidizers are broad-spectrum agents that are most commonly used in non-oilfield applications (e.g., water treatment) and include chlorinated products, oxygenated products, and brominated products. Non-oxidizers are more specific and less corrosive than oxidizing biocides. They are more common to oilfield operations and can be broadly grouped by their mode of action into metabolic inhibitors and surface-active agents.

Metabolic inhibitors damage enzymes and protein structures, inhibiting the transport of nutrients or other molecules, and affect other metabolic processes. Included in this class of non-oxidizing agents are:

- Aldehydes (formaldehyde, glutaraldehyde)
- Quaternary phosphonium salts (THPS)

- Sulfur compounds (isothiazoline, carbamates, metronitazole)

Surface-active agents are organic products with functional groups that attach to cell surfaces. These agents alter or destroy cell membranes and walls or affect the cell's ability to regulate its internal environment. Included in this class of non-oxidizers are:

- Filming amines (diamines or quats)
- Surfactants (generally not very biocidal so they are used with other biocide products to help disrupt or remove biofilms and increase biocide dispersability or penetration)

Simulating field conditions to evaluate biocide performance may be difficult or impossible. The most reliable test apparatus is the operating environment. No source of information should be ignored in evaluating additives or process variables. Much valuable data can be obtained if detailed day-to-day records are kept on equipment performance. Laboratory kill tests of artificial consortia (combining laboratory strains of various bacteria types) or natural communities recovered from actual oilfield systems are used to screen potential biocide products for field testing. Field tests include evaluating the biocidal effectiveness on planktonic bacteria (and serve as additional screening), but they do not sufficiently indicate effectiveness on sessile populations (i.e., biofilms) unless sessile bacteria are evaluated. Coupons can be used as the final indicator of biocide effectiveness to indicate microbial attack of metal surfaces. Typically, one coupon would be installed in a system upstream of injection and another would be placed sufficiently downstream for a prescribed period of time. The coupons would then be analyzed to determine treatment efficacy.

2.2.5.3 Corrosion Inhibitors

Corrosion inhibitors are excellent agents for modifying an environment that would ordinarily support corrosion. Most corrosion inhibitor components can be classified as:

- Amides/imidazolines
- Salts of nitrogen containing molecules with carboxylic acids
- Nitrogen quaternaries
- Filming oxyalkylated amines, amides, and imidazolines

- Nitrogen heterocyclics and compounds containing phosphorus, sulfur, and oxygen

An important distinction between inhibitors is their solubility — whether they are oil-soluble only or soluble in oil and dispersible in water. Oil-soluble, water-dispersible products typically perform best when sufficient mixing due to flow velocities can be maintained. Most inhibitors form some type of film on the protected metal surface. Mechanisms by which inhibitors work may best be described as follows:

- Adsorption to form a thin film on the surface of a corroding material
- Changing the characteristics of the corrosion product film to make it more protective
- A mixture of the two methods

These mechanisms cover most of the observed effects and form the basis for experimental work leading to the development of inhibitors as well as strategies for their use. The criteria for selecting a corrosion inhibitor are the:

- Capability to be delivered to corrosive locations
- Ability to prevent corrosion when present at those locations
- Compatibility with the existing process and operations price

Any corrosion that occurs will be in the water-wet area in the presence of a hydrocarbon/water mixture. Therefore, it is desirable for a corrosion inhibitor to partition into the water phase. In natural gas pipelines, hydrocarbons and water condense from the gas phase at certain temperatures and pressures (depending on the gas-phase composition). Typical gas condensates are organic molecules with three to ten carbon atoms (i.e., propane to decane). The quantity of liquid hydrocarbons in a pipeline system is an important consideration with regard to corrosion risks and corrosion mitigation schemes. For example, if the hydrocarbons represent the continuous phase and water the dispersed phase, then the majority of the system components will be exposed to the less-corrosive hydrocarbon phase. With water as the continuous phase, this represents a more corrosive situation. Careful selection of aqueous-phase corrosion inhibitors should be done to ensure that unwanted inhibitor partitioning to the hydrocarbon phase is minimized. In addition, some hydrocarbons are known to be capable of reducing internal corrosion by filming metal surfaces and/or having corrosion-inhibitory qualities.

It is important to note that partitioning behavior of oil-soluble/ water-dispersible inhibitors can depend on the pH of the water. In the presence of condensate, oil-soluble corrosion inhibitors can emulsify the water present, keeping the pipe walls oil-wet and thereby inhibiting corrosion. Candidate products are evaluated based on the information provided by a vendor and testing (both in the laboratory and in the field). When selecting a corrosion inhibitor, its level of compatibility with other processes should be ascertained. Some inhibitors tend to cause emulsion and foaming problems and are therefore delivered with additives to prevent these effects. Some inhibitors may also dissolve certain elastomeric materials in seals, liners, or diaphragms. In addition, temperatures greater than 180°F (82°C) may be detrimental to the inhibitor's stability.

Laboratory tests are recommended for evaluating new candidate inhibitors. The purpose of laboratory testing is to determine relative effectiveness between products, including the concentration required for protection, partitioning behavior, and effectiveness in aggressive environments. A common laboratory test is conducted on a benchtop with 100% CO_2 bubbled through the test solution at atmospheric pressure. Sometimes a metal sample is placed in the water phase, and a varied level of inhibitor is added to a hydrocarbon phase. This test is sometimes used to indicate if the chemical partitions to the water and inhibits corrosion at a minimum concentration. It is a qualitative test, but any chemical that fails this test should not be considered for field application or field trials. More sophisticated laboratory tests are available to better evaluate inhibitor performance with respect to the relevant field characteristics.

A new inhibitor candidate that has passed laboratory testing should be evaluated in the field on a small scale utilizing corrosion monitoring tools. It is important to select a location that accurately represents the system of interest and has sufficient monitoring capability. After downhole treatment, monitoring locations should be far upstream for batch treatments and far downstream for continuous treatment. In any case, monitoring should adequately cover the vulnerable areas regardless of the distance from the pipeline start.

2.2.5.4 Natural Gas Dehydration

Water, as a continuous liquid phase, represents a serious corrosive situation. Water vapor by itself cannot support corrosion because it is not an electrolyte. Water can adsorb to a metal surface at low humidity resulting in negligibly low corrosion rates. At the vapor phase concentration where water condenses, corrosion can occur provided that other environmental conditions exist. Removal of water vapor from natural gas is therefore a viable means of corrosion control through environmental control.

Water vapor is typically removed from natural gas through the use of tri-ethylene glycol (TEG) and, occasionally, di-ethylene glycol (DEG). Glycol efficiently absorbs water (i.e., it is hygroscopic) and can be regenerated by heating because glycol has good stability to heat and low vapor pressure. Water is therefore removed by cyclically absorbing it from the gas stream at low temperature and removing the water from the glycol by heating. Upsets in glycol dehydration units and carryover of glycol mist are common and steps are usually taken to minimize this problem.

Water vapor coexists with liquid water when the partial pressure of water in the gas phase equals the vapor pressure of the liquid phase (dew point). The partial pressure of water vapor (or any other gas component) is found by analyzing a gas sample for its content and making the calculation as shown below. Once the mole % (volume %) of water vapor, in relationship to the entire gas sample, is measured, that mole % is multiplied by the total pressure to calculate partial pressure.

$$\text{partial pressure} = \frac{[\text{mole \% x total pressure}]}{100}$$

where:

total pressure (psia) = [pressure (psig) + atmospheric pressure (14.7 psi)]

Above the dew point (i.e., at higher temperatures or lower pressures), water vapor exists without a condensed liquid phase (i.e., it is superheated). However, the point at which water wets a surface (i.e., local dew point) is not fully represented by commonly used dew point measurements (e.g., ASTM D-1142-95 [2000]) because the humidity at which water condenses on a surface depends in part on the character of that surface.

Note that using a mass-per-standard-volume specification to prevent water condensation throughout an entire pipeline system (and downstream distribution lines) is conservative for the majority of individual pipelines within a transmission system. Gas quality specifications are set for commercial considerations and typically include maximum water content in terms of weight per standard volume. The water content criterion is determined by several engineering considerations, including preventing corrosion, preventing blockages from freezing, hydrates, and affecting the heating value of natural gas. The water content criterion of 7 lbs/ MMSCF (pounds per million standard cubic feet) or other similar specification does not necessarily correlate with the critical water vapor content sufficient to support corrosion because other factors (e.g., pressure and temperature) also determine the point at which water condenses.

2.2.5.5 Maintenance (Cleaning) Pigging

Pigging is an effective method of altering the internal environment of a pipeline. Internal corrosion of pipelines is usually associated with water. Gas and condensate pipelines are vulnerable to water accumulation from condensation and water carryover due to operational upsets. Dehydrators and separators are not always completely effective.

Maintenance pigging is used to remove accumulated water, debris, sludge and other solid deposits. This helps to maintain throughput capacity and the desired flow parameters. Removing deposit and debris helps to avoid under deposit internal corrosion and supports the integrity assurance of pipelines. To ensure pipeline integrity and optimal effectiveness of internal corrosion control, close coordination of operational pigging and application of treatment chemicals is crucial.

Conventional pigs are more commonly described as cleaning pigs used to remove accumulated liquids/solids/deposits which could obstruct flow or cause corrosion. Sealing pigs are used either to provide a good seal against the wall of a pipeline to sweep liquids from the line or to separate two dissimilar liquids in the pipeline. For batch biocide treatment, the chemical is run between two sealing pigs to enable the biocide to contact the full circumference of the pipe to poison all the microbial biofilm colonies and kill all the bacteria residing in the pipeline.

Pigging schedules are generally based on the amount of material accumulated in the line and pushed out by each pigging event. Through the different stages in the life of a pipeline, the type and frequency of pigging may vary — as do the type of pigs (e.g., spheres, scrapers, brush) that are used.

2.2.5.6 Environmental Stress Corrosion Control

Stress arising from fabrication, transportation, installation, and operation of the pipeline contribute to the material's threshold stress. The combination of such stress and a hostile environment are responsible for environmental stress corrosion. The prevention or mitigation of such corrosion calls for enlightened design with proper material selection, modification of the stress state and the environment within and outside the pipeline.

Environmental stress corrosion could be significantly mitigated by (1) proper alloy selection, (2) removing or reducing the source of the enduring tensile stresses, (3) assuring the presence of residual compressive stresses at the surface, and (4) by altering the environment. The various SCC control methods appear in Figure 2.21.

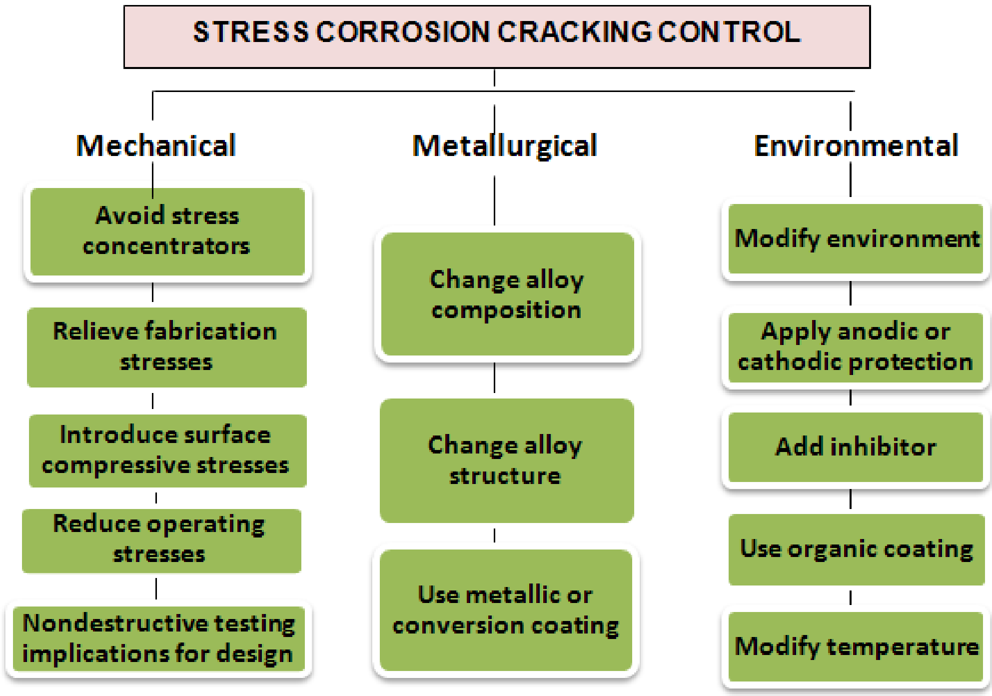


Figure 2.21 Key Stress Corrosion Cracking Control Methods

Sulfide stress cracking could be controlled by careful material selection and by modification of welding practices. The hardness areas, resulting from welding, should not exceed 248 HV10 in order to avoid sulfide stress cracking. Seamless pipe is far more resistant to hydrogen induced cracking than submerged arc weld (SAW) or other pipe made from rolled steel products. Chloride-induced cracking may be avoided by eliminating crevices where chlorides may concentrate.

The key to avoiding hydrogen induced cracking, and indeed, environmental stress corrosion cracking, is to adhere to NACE MR0175/ISO 15156.

2.2.5.7 Design

Design is a fundamental means of avoiding or controlling corrosion. Examples where designs are effectively utilized for the greatest effect include process layout design, coating design, inspection design, corrosion monitoring design, design of chemical treatment methodology, design for effective pigging operation, piping design for water traps, drips, dead legs, dead lines, and flow hydrodynamics. Designs are also utilized to effect deposit control, oxygen exclusion, and the control of microbes. Designs are effective in the prevention of oxygen entry into pumps, water supply wells, water injection wells, and producing wells. Properly designed vacuum towers or counter-current gas stripping towers ensure the removal of oxygen from fluids.

In pipeline design, the presence of crevices and improper joining should be avoided as they lead to corrosion. Designs for welded joints should be implemented to avoid incomplete weld penetration that would ordinarily result in crevices. In some designs such as lap joints, crevices are inherent and should be properly sealed. If possible, butt joints should be used in preference to lap joints. Resilient gaskets or sealants with long lifetimes may be used to avoid crevices altogether. Some design techniques allow the use of aluminum mating parts that could be cathodic within the crevice.

A proper design is required to avoid the introduction of moisture into the crevices. In the event that moisture accumulation is inevitable, the design must seek to provide complete drainage of the crevices. Effective drainage of facilities is vital to prevent fluids from becoming trapped in crevices. Areas such as this must be inspected regularly and cleaned thoroughly. The use of thermal insulation that could hold moisture in contact with metals should be avoided.

Pipeline supports should be designed with metal cradles and welded saddle seals to prevent water or debris accumulation under the pipe.

Dead legs, dead lines, drain lines and drips cannot be avoided in any production field. These are pipe sections that are characterized by stagnant or intermittent flow conditions, where corrosion could develop unnoticed and thereby compromise pipeline integrity. Appropriate designs to avoid fluid stagnation plus monitoring would correct this situation. Another option is to design dead legs and drips so they can easily be inspected and cleaned.

2.3 Time-Related Pipeline Defect Types

According to ASME B31.8S, the three time-related defect types that could compromise the integrity of a pipeline are internal corrosion, external corrosion and stress corrosion cracking.

2.3.1 Internal Corrosion

The summary of the selected eight forms of corrosion depicted in Table 2.2 plus the accompanying discussions represent the prevailing internal corrosion mechanism to varying degrees. Generally, the key internal corrosion variables include:

- temperature
- total pressure
- partial pressures of dissolved gases
- conductivity
- electrolyte pH
- dissolved gases
- fluid velocity.

Like almost all other chemical reactions, corrosion rates generally increase as temperature increases. A rough "rule of thumb" suggests that the reaction rate doubles for every 10-degree Celsius rise in temperature. However, there are exceptions to the rule. The solubility of dissolved gases decreases with temperature. As the solution gets hotter, dissolved corrosive gases come out of solution and the corrosivity of the water (electrolyte) decreases. Increasing temperature may also raise a gas above its water dew point, thereby decreasing corrosion.

The oil and gas production assets generally affected by internal corrosion are downhole equipment, wellheads, flowlines, gathering systems, transmission pipelines, water treatment plants, storage tanks, water injection and disposal facilities. Internal pipeline corrosion is normally within the corrosion allowable range until water is co-produced with oil and gas. This is because corrosion is sustained exclusively by electrolytic current. The electrolytes responsible include bottom sediment and water, dissolved acid gas, dissolved organics, suspended organics, dissolved inorganics, suspended inorganics, dissolved solids, suspended solids, and the metabolic products of microbes. In general, chloride-containing waters tend to be more corrosive than those without chloride and the presence of chlorides (or other halogens) prevents the formation of protective films and increases corrosion. Similar constituents in the water entrained in gas cause corrosion of natural gas pipelines.

Although dissolved oxygen creates special corrosion problems, it is not naturally present in sub-surface formations. Oxygen is not a factor in most of the internal corrosion of natural gas systems because it is not usually present in produced gas and its ingress is minimized. Because it is present in the atmosphere and is sufficiently soluble in water, it is therefore, present in all surface waters. It also dissolves in non-surface water through open tanks, leaking seals or trucked fluids. The solubility of oxygen is greater at low temperatures and in water having low total dissolved solids (TDS).

Oxygen causes severe pitting attack even at very low concentrations of less than 50 parts per billion (ppb). Generally, the corrosion of iron dramatically accelerates in the presence of oxygen. Oxygen is a powerful cathodic depolarizer. It also changes protective scales to non-protective scales. It promotes oxidation reaction and converts H_2S to sulfur. Its presence causes the formation of lumps of corrosion products called tubercules.

In natural gas pipelines, oxygen is typically introduced in areas of suction (e.g., pumps) where air is drawn into gas processing, treating, or handling equipment. If the natural gas systems contain water, significant increases in general corrosion are often observed. These increases are largely due to O_2 being a strong oxidizing agent. Oxygen accelerates corrosion pitting, especially when mixed with CO_2 and/or H_2S, in the presence of wet gas or free water. When O_2 is present, it is not uncommon for pitting rates to increase ten times. As a rule of thumb, dissolved O_2 concentrations above 0.05 ppm (50 ppb) measured in water are considered to be corrosive. Turbulent flows at restrictions, bends, etc., accelerate dissolved O_2 corrosion rates.

Water dissolves most inorganic matter as well as some organic compounds. In many cases, these materials — either in solution or suspension — increase the corrosivity of water and may influence scaling or fouling. In general (but not always), an increase in the total amount of dissolved solids results in an increase in the corrosion rate. The source of dissolved solids is most commonly carryover from a production system. Increases in the ionic content of the water, however, can also limit the solubility of other corrosive agents such as oxygen, carbon dioxide, and hydrogen sulfide. Solutions containing organic or mineral acids having pH levels of 5.0 or less may result in increased corrosion.

When water contains cations such as calcium (Ca^{++}), magnesium (Mg^{++}), barium (Ba^{++}), and/or strontium (Sr^{++}), the water is said to be "hard." Carbonates in the water serve as an acid buffer, which usually decreases the corrosion rate. In gas pipelines, calcium carbonate and other insoluble salt formations can form scales that may inhibit corrosion by forming a barrier between the water and the metal surface. On occasion, these scales may generate enough bulk to hinder flow. Water without the above cations is said to be "soft" and without buffering capacity and is more corrosive.

In natural gas pipelines, soft water is often the result of condensation of water from wet gas. It is possible to reduce or prevent corrosion through minimizing entry of water and limiting the levels of potentially corrosive gases (i.e., carbon dioxide [CO_2], hydrogen sulfide [H_2S], and oxygen [O_2]). Gas and liquid quality standards are set, in part, to minimize internal corrosion. However, pipeline gas corrosivity cannot be determined from gas quality standards alone. System upsets can cause corrosive conditions to exist for periods of time, capable of initiating internal corrosion. Because of the complex nature of, and interaction between, constituents that make up gas (e.g., O_2, CO_2, H_2S, etc.) and aqueous liquids (e.g., chloride, bacteria, etc.), certain combinations of these impurities may affect whether a corrosive condition exists. Gases, liquids, and operating conditions are monitored and evaluated on an individual basis in order to accurately assess the effects of their presence and/or absence in the pipeline.

In liquid petroleum pipelines, it is possible to prevent internal corrosion by complete removal of water from the system, avoiding operating conditions where water could settle out, or treating the water with corrosion control chemicals. Often, complete removal of water is not practical (or possible), particularly in gathering systems. Supplemental corrosion inhibitors are frequently needed to reduce corrosion to an acceptable rate, provided that the inhibitors reach the metal surface and form a persistent surface film (or barrier) against residual water. Pigging may also be required to get the chemical to the pipe surface and to remove solids.

2.3.2 External Corrosion

External corrosion on pipelines derives principally from two sources; namely: (1) galvanic cell on the pipeline; and (2) stray current. Galvanic cells exist on the pipeline because of potential differences along the external pipe surface whereby one surface location serves as the anode and another location serves as the cathode. A variety of electrolyte sources provide the essential medium for ionic current corrosion including:

- Differential oxygen concentration at the two surface locations
- Changes in soil type at the two surfaces locations
- Differences in conductivity due to presence of groundwater, sea-water, salt spray or other weathering conditions
- Metabolic processes of microbes
- Connection to other metals, e.g., well casings to flowlines

The second source of external pipeline corrosion is stray current flow between the prevailing environment and buried or submerged pipelines. A variety of stray current sources are as follows:

- DC transit systems
- DC mining operations
- Electrical grounding rods
- Grounded cathodic protection system for an adjacent buried pipeline
- DC welding operations
- High voltage DC transmission system
- Geomagnetic (telluric) earth currents
- AC current flow to ground
- Defective electrical isolation joints
- Contact with other metallic structures

The accompanying discussion provides a summary of the different forms of corrosion, each of which (except velocity related corrosion) contains some elements of external corrosion mechanism to varying degrees.

2.3.3 Stress Corrosion Cracking (SCC)

The crack in the American Liberty Bell in Philadelphia, with essentially no metal loss, illustrates a typical characteristic of SCC. Figure 2.22 illustrates other examples of SCC.

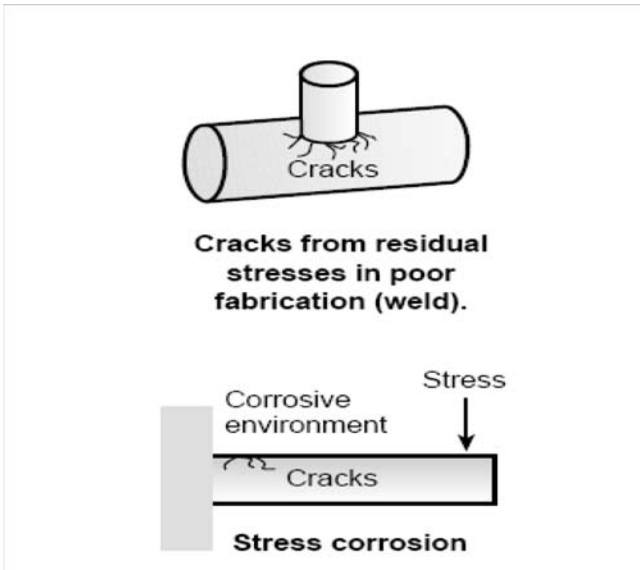


Figure 2.22 A Schematic Illustration of Stress Corrosion Cracking

Stress corrosion cracking is the undesirable interaction of corrosion (chemistry) and mechanical stress (physics) that is capable of causing catastrophic rupture of high-pressure transmission pipelines in the presence of little or no metal loss. Stress corrosion cracking has occurred on gas and hazardous liquid pipelines, but pipeline incidents due to SCC happen more frequently in natural gas lines due to higher pipeline temperatures and pressures. About 1% of pipeline failures are due to SCC. The first reported case was in 1977 at Nova Scotia, Canada. This was followed by three major failures in 1985 and 1986 on trans-Canada pipelines. There were several reported failures in the 1990s including the one depicted in Figure 2.23, which was accompanied by rapid crack propagation.

Figure 2.23 SCC-Induced Gas Pipeline Rupture (1999) Accompanied With Rapid Crack Propagation
(RCP) (32" O.D. x 0.25 w.t. API 5L Grade X60; MAOP=434 psi)

SCC is an environmentally-assisted phenomenon and the following three conditions must exist simultaneously in order for SCC to take place:

- The use of SCC susceptible material for the given application
- The presence of sufficiently high strength, imposed on the susceptible material
- An environment that causes SCC for the susceptible material

Because three simultaneous conditions are required for its occurrence, SCC is relatively infrequent and unpredictable. Its occurrence depends on the electrochemical potential of the material as well as the electrode potential of the applied CP. Material composition, microstructure and heat treatments also affect SCC susceptibility. SCC is associated with sour or sweet corrosion depending on the susceptible material and its state of stress.

Stress is always a necessary requirement for SCC and the cracking may occur at stresses considerably below the yield stress of some alloys. This may be due to the effects of the threshold stress intensity factor. The value of this factor depends on the combination of threshold stress, the geometry of the component and the maximum defect size. Stress corrosion cracks could propagate over a range of velocities from about 10^{-3} to 10 mm/hour, depending on the susceptible material, its surface condition, the potency of the environment, and the threshold stress intensity factor.

Not all stress corrosion cracks result in catastrophic failures; that event depends on the source of stress. For example, crack propagation may be a source of relief for fabrication stress. If, however, a sustained stress derives from the operating conditions and all other causative conditions of SCC are present, catastrophic failure may occur if the stress intensity factor is above the threshold value.

2.3.3.1 Sweet-Corrosion Induced SCC

Two types of SCC are associated with sweet corrosion in carbon steel; namely: high pH SCC and near neutral pH SCC. The SCC causative environments were found on the exterior surface of carbon steel pipelines. ERW and double submerged arc weld (DSAW) have been involved in SCC related failures. Tensile residual stresses in the pipeline and hoop stress produced by internal pressurization are strong causative factors in SCC.

High-pH SCC is found ten miles downstream of compressor stations where the highest temperatures are present. It is occasioned by the failure of coal tar or asphalt coatings. Many high-pH SCC failures occurred in API 5L X-52 (ASTM Grade 358). They occurred in carbonate or bicarbonate environments with a pH higher than 9 and a temperature of about 100^{o}C. SCC cracks are found along the bottom half of the pipeline at locations where the yield strength of the pipeline material has been exceeded and cathodic protection has been rendered ineffective by the attendant plastic deformation of the pipe.

The near-neutral pH SCC typically occurs where there is a combination of inadequate CP and a pitting corrosion site within groundwater containing dissolved carbon dioxide. Many near-neutral pH SCC failures occurred on grades varying from API 5L X-35 (ASTM Grade 241) to API 5L X-65 (ASTM Grade 448). The accompanying cracks are wide in comparison to those resulting from high-pH SCC. The cracks are usually oriented in the axial direction and can range from a cluster of cracks to hundreds of cracks. The cracks tend to interlink and form long shallow flaws.

The resulting rupture fracture faces are normally covered with carbonate and magnetite films.

What are the reasons a CO_2 environment is viewed as one of the primary causes for the two types of SCC?

Carbon dioxide (CO_2) is an odorless, colorless gas present at varying levels in virtually all natural gas. Carbon dioxide is also present in the atmosphere and is so significantly soluble in water as to be present in virtually all surface waters.

When CO_2 is at a sufficient partial pressure in the presence of water (depending on the water's chemistry), internal corrosion will occur. CO_2 corrosion is also referred to as "sweet" corrosion because of the absence of sour gas (hydrogen sulfide [H_2S]). When soft water is present, such as that formed from condensation of water vapor, CO_2 becomes very corrosive by forming carbonic acid (H_2CO_3) as shown in the following equation.

$$CO_2 + H_2O \longrightarrow H_2CO_3$$

With carbonic acid, the pH of the water in the system decreases and the corrosion rate increases. Although carbonic acid is a weak acid, the corrosivity of dissolved CO_2 is quite high due principally to the cathodic reaction of the un-dissociated carbonic acid. Also, a bicarbonate solution is generally more corrosive than fresh water because a bicarbonate ion is a potent electrolyte and the higher the conductivity of an electrolyte, the greater the chance for corrosion. Dissolved in hard water, CO_2 forms carbonates (CO_3^{2-}) and/or bicarbonates (HCO_3^-) providing a protective scale in the form of salts such as calcium or magnesium carbonate and calcium bicarbonate on the surface of the pipeline. Bicarbonates also work as a buffering agent by consuming acids (H^+) and not allowing them to decrease the pH and become corrosive. However, the effect of buffering is slightly countered by the effect of bicarbonate as a cathodic reactant.

Some of the factors that determine the solubility of CO_2 are pressure, temperature, and the composition of the water. In soft water systems, the CO_2 corrosion rate rises when the partial pressure of CO_2 increases. The partial pressure of CO_2 (or any other gas component) is found by analyzing a gas sample for its content and making the calculation as shown below. Once the mole %

(volume %) of CO_2 gas in relationship to the entire gas sample is measured, that mole % is multiplied by the total pressure to calculate CO_2 partial pressure.

$$\text{partial pressure} = \frac{[\text{mole \% x total pressure}]}{100}$$

where:

total pressure (psia) = [pressure (psig) + atmospheric pressure (14.7 psi)]

Compared with oxygen, CO_2 is not as corrosive. However, like O_2, carbon dioxide results in severe pitting in those areas (such as the heat-affected zones) that are particularly susceptible to "sweet corrosion." Corrosion in the form of general wall loss and pitting is far more severe in a CO_2 dominated environment than in H_2S dominated systems. In a gas containing both CO_2 and H_2S, the dominant component is CO_2 if its partial pressure exceeds that of H_2S, by a factor of more than 10–20.

Crack initiation often starts at sites where pitting processes occur in CO_2 dominated environments. If the incipient pitting cracks are deep and narrow with rapid penetration, stress corrosion cracking may result from the interaction of operating stress and the pitting. The cracks may indeed reach a depth at which pipeline failure may result from third party contact or excessive pipe pressure. Pitting corrosion is normally surrounded by non-corroded region, a noted characteristic of SCC failure.

The key issues that influenced occurrences of recorded catastrophic SCC failures that were documented for high-pH SCC and near neutral-pH SCC are as follows:

- Coating types (polyethylene tape, asphalt, coal tar, epoxy)
- Soil conditions (type, drainage, topography, CO_2 level, CP condition)
- Susceptible pipe (manufacture, yield strength, surface conditions, temperature)
- Stress conditions (radial, axial, plastic deformation, operational stress)

Because of this observation, predictive corrosion models were developed that sought to categorize areas with "significant" or "non-significant" SCC threats. The models are based on factors including the coating type, pipeline installation date, pipeline operating history, soil type, drainage, topography, and levels of cathodic protection. The best of these models has been 44% accurate in its SCC prediction.

2.3.3.2 Sour Corrosion Induced SCC

Sour corrosion induced SCC is associated with sulfide stress cracking (SSC), hydrogen induced cracking (HIC) (also known as stepwise cracking (SWC)), stress-oriented hydrogen induced cracking (SOHIC), and hydrogen embrittlement (HE). For SCC caused by hydrogen embrittlement processes, the higher the alloy strength, the more susceptible is the material to SCC. As shown on Table 2.7, sour corrosion induced SCC has been observed in corrosion resistant alloys (CRA) such as duplex stainless steel and martensitic stainless steel.

Table 2.7: Common SCC Systems
(Source: National Physical Laboratory)

Material	Environment	Concentration	Temperature	Failure Made
Carbon steel	Hydroxides	Around 1 molar Up to 1 molar	Around boiling	Intergranular
	Nitrates	Up to 10^{-2} molar	Below 100°C	Intergranular
	Carbonates/ Bicarbonates	---	Below 100°C	Intergranular
	Liquid ammonia	---	Ambient	Transgranular
	$CO/CO_2/H_2O$	---	Ambient	Transgranular
	Aerated water		Above boiling	Transgranular
Low alloy steel	water	---	Below 100°C	Transgranular
Austnitic stainless steel	Chloride	Around 1 molar	Around boiling	Transgranular
	Hydroxide	Around 1 molar	Around boiling	Transgranular
Duplex stainless steel	Chloride	Around 1 molar	Around boiling	Transgranular
	Chloride + H_2S	Around 1 molar	Below 100°C	Transgranular
Martensitic stainless steel	Chloride + H_2S	Up to 1 molar	Ambient	Transgranular

Carbon steel welded piping containing wet fluids in equilibrium with gas containing H_2S exceeding a partial pressure of 1.5 psi is susceptible to SCC. The SCC causative environments were found in the interior surfaces of the pipelines. The relevant environmental parameters that affect sour corrosion induced SCC are as follows:

- H_2S concentration
- Chloride concentration
- Temperature
- Flow velocity
- Water cut

Generally, the susceptibility of metallic materials to cracking in H_2S (sour) service depends on H_2S partial pressure, in situ pH, the concentration of dissolved chloride or other halides, the presence of elemental sulfur or other oxidants, temperature, galvanic effects, mechanical stress, and exposure time to liquid water phase. The partial pressure of a component of gas, such as H_2S, equals the total pressure times the mole fraction of the component.

The partial pressure of H_2S (or any other gas component) is found by analyzing a gas sample for its content and making the same calculation as used for $C0_2$. Once the mole % (volume %) of H_2S gas in relationship to the entire gas sample is measured, that mole % is multiplied by the total pressure to calculate H_2S partial pressure.

$$\text{partial pressure} = \frac{[\text{mole }\%] \times [\text{total pressure}]}{100}$$

where:

total pressure (psia) = [pressure (psig) + atmospheric pressure (14.7 psi)]

That is, the partial pressure of H_2S equals the total pressure times the mole fraction of H_2S. The mole fraction is not a function of pressure, but the partial pressure is. Hence, the gas stream that lacked sufficient H_2S to promote HIC in one part of the process may be sufficiently aggressive to promote HIC in a low pressure location of the same process. The NACE Standard MR0175 guideline for the use of carbon steel in sour service is for the partial pressure of H_2S to be at least 0.05 psia (0.0003 MPa). Some companies adopt a limit of 2 ppm H_2S limit rather than a partial pressure limit.

2.3.3.3 SCC Caused by Other Factors

In general, the initial mechanisms for incipient SCC catastrophic failures are associated with localized pitting whose further growth and development is supported by the local stress intensity factor. Consequently, environments dominated by systems such as dissolved O_2, aerated water, water, nitrate ions, sulfate ions, chloride ions, hydroxide ions, liquid ammonia, MIC, etc. may be potent enough to support SCC.

Other causative mechanisms may include intergranular or intercrystalline fracture (IGC), transgranular/transcrystalline fracture, and de-alloying cleavage.

2.3.4 Corrosion Detection Methods

Inspection and monitoring are the two key processes by which the onset of internal corrosion, external corrosion and stress corrosion cracking can be detected early. Early detection assists corrosion risk criticality assessment, helps ensure reliability of production and enables the avoidance of losses from equipment replacement and operational disruptions.

Surface equipment can be inspected visually and with non-destructive techniques such as calipers, magnetic flux leakage, ultrasonic inspection, etc. Tank bottoms can also be inspected visually, by ultrasonic inspection, or electromagnetic flux leakage techniques. Applicable inspection methods include profile type corrosion caliper tools, electromagnetic casing inspection tools (smart pigs), electromagnetic flux leakage tools, electronic casing tools, and downhole cameras.

2.4 Inspection Methods

2.4.1 In-Line Inspection (ILI) Tools

In-line inspection (ILI) terminology covers various types of tools such as corrosion detection tools, crack detection tools, deformation detection tools, self-propelled, fluid-propelled, cable-pull and crawler tools. Table 2.8 presents the inspection purposes, anomaly types, and ILI tools to detect all of the 21 threats to pipeline integrity. For the specific measurement of pipeline thickness losses due to corrosion, the three primary tools used are (1) standard resolution magnetic flux leakage; (2) high resolution magnetic flux leakage; and (3) ultrasonic compression wave tool (this is only useful in liquid environment). The crack detection tools are the ultrasonic (shear wave) and transverse MFL

The advantages and disadvantages of the ILI tools used for assessing internal, external corrosion and stress corrosion cracking appear in Table 2.9.

2.4.2 Hydrostatic Testing

The use of hydrostatic testing for inspection purposes is based on the supposition that the line is safe to operate at the maximum operating pressure (MOP) and below after defects that fail above the MOP are removed. It involves filling the pipeline with water and raising the pressure to a specified level based on design and service pressure criteria. It is a low-technology technique whose integrity conclusions are relevant only at the time of the test.

2.4.3 Direct Assessment Inspection Methods

For the time-dependent defect types, the three Direct Assessment Inspection methods used are internal corrosion direct assessment (ICDA), external corrosion direct assessment (ECDA), and stress corrosion cracking direct assessment (SCCDA).

Direct assessment is a structured process that uses data and information from indirect pipeline survey techniques and direct examination of pipelines along with all other relevant information (e.g., design, construction and operating data) to assess the condition of a pipeline. It is a four-step process consisting of (1) pre-assessment, (2) indirect inspection, (3) direct examination, and (4) post assessment. Each is a non-destructive inspection methodology that can be used to inspect and assess pipelines and flowlines that cannot be pigged or subjected to hydrostatic testing.

Table 2.8: Inspection Purposes, Anomaly Types, and ILI Tools to Detect Them

ILI PURPOSE	METAL-LOSS TOOLS			CRACK-DETECTION TOOLS		CALIPER TOOLS	MAPPING TOOLS
	Magnetic Flux Leakage (MFL)		Ultrasonic (compression wave)	Ultrasonic (shear wave)	Transverse MFL		
	Standard-resolution (SR) MFL	High-resolution (HR) MFL					
METAL LOSS (CORROSION) External corrosion Internal corrosion	detection,[A] sizing,[B] no ID/OD[C] discrimination	detection,[A] sizing[B]	detection,[A] sizing[B]	detection,[A] sizing[B]	detection,[A] sizing[B]	no detection	no detection
NARROW AXIAL EXTERNAL CORROSION	no detection[A]	no detection[A]	detection,[A] sizing[B]	detection,[A] sizing[B]	detection,[A] sizing[B]	no detection	no detection
CRACKS AND CRACK-LIKE DEFECTS (Axial) Stress corrosion cracking Fatigue cracks Longitudinal seam weld imperfections Incomplete fusion (lack of fusion) Toe cracks	no detection	no detection	no detection	detection,[A] sizing[B]	detection,[A][D] sizing[B]	no detection	no detection
CIRCUMFERENTIAL CRACKING	no detection	detection,[D] sizing[D]	no detection	detection,[A] sizing[B] if modified[E]	no detection	no detection	no detection
DENTS SHARP DENTS WRINKLE BENDS BUCKLES	detection[F]	detection,[F] sizing not reliable	detection,[F] sizing not reliable	detection,[F] sizing not reliable	detection,[F] sizing not reliable	detection,[G] sizing	detection, sizing not reliable
	In case of detection, circumferential position is provided.						
GOUGES	Detection[A] and Sizing[B]						no detection
LAMINATION OR INCLUSION	limited detection	limited detection	detection, sizing[B]	detection, sizing[B]	limited detection	no detection	no detection
PREVIOUS REPAIRS	detection of steel sleeves and patches, others only with ferrous markers		detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches, others only with ferrous markers	no detection	no detection
MILL-RELATED ANOMALIES	limited detection	limited detection	detection	detection	limited detection	no detection	no detection
BENDS	no detection	no detection	no detection	no detection	no detection	detection, sizing[H]	detection, sizing
OVALITIES	no detection	no detection	no detection	no detection	no detection	detection, sizing[B]	detection, sizing[B][I]
PIPELINE COORDINATES	no detection	no detection	no detection	no detection	no detection	no detection	detection, sizing

(A) Limited by the minimum detectable depth, length, and width of the defects.
(B) Defined by the specified sizing accuracy of the tool.
(C) Internal diameter (ID) and outside diameter (OD).
(D) Reduced probability of detection (POD) for tight cracks.
(E) Transducers to be rotated by 90°.
(F) Reduced reliability depending on the size and shape of the dent.
(G) Depending on the configuration of the tool, also circumferential position.
(H) If equipped for bend measurements.
(I) If the tool is equipped for ovality measurement.

Shaded area indicates ILI technologies that can be used only in liquid environments, i.e., liquids pipelines or in gas pipelines with a liquid couplant.

Table 2.9: Advantages and Disadvantages of Selected Corrosion Detection Tools

Technology	Advantages	Disadvantages
Magnetic Flux Leakage	Can detect and measure corrosion pit depths down to 7 mm in diameter	
	Well suited for thin wall pipe or small diameter pitting	Does not see defects which do not cause a leakage field
	Can detect radial cracks in the circumferential girth welds	Cannot inspect austenitic stainless steel pipelines due to low magnetic permeability
Eddy Current	Relatively Inexpensive	Low throughput
	Good Resolution	Interpretation of output
	Multi - Layer Capability	Operator training
	Portability	Human actors (tedium)
Ultrasonic	Good Resolution	Single-Sided
		Requires couplant
	Can Detect Material Loss and Thickness	Cannot assess multiple layers
		Low throughput
Shear Wave	Best Resolution (~1%)	Expensive
	Image Interpretation	Bulky Equipment
	Predicts corrosion before it has a chance to develop serious metal loss features	
Radiography	Good Resolution	Errors due to edge projection uncertainties
	Can detect material loss and thickness	Defect depth measurement in radiation direction depends on relative proportional approach
		Film radiography is not amenable to digital processing

2.4.4 Internal Corrosion

Inspection for internal pipeline corrosion usually hinges on the consideration of the following factors:

- Nature of product transported
- Flow rate/velocity
- Presence of hydrogen sulfide and/or carbon dioxide
- Water content and dew point
- Elevation/inclination of pipeline or flowline
- Internal coating
- Weld quality and joint type
- Water chemistry and microbiology
- If line is piggable or routinely pigged
- Knowledge of previous internal corrosion
    - Mitigation history
    - Operational history
    - Physical conditions such as pressure and temperature
    - Design and construction factors

The Internal Corrosion Direct Assessment (ICDA) process addresses the following issues:

- **Integrity assessment**: This answers the question “Is there a risk of internal corrosion in this facility?”
- **Corrosion investigation**: This step determines if any actions are required to control internal corrosion in the facility.
- **Mitigation and monitoring**: This answers the question “What must be done to mitigate internal corrosion in this facility?”
- **Assessment frequency**: This step answers the question “How is integrity managed long term?”

Although ICDA is specific to dry natural gas transmission lines that may experience occasional upsets which introduce water into the system, the basic concepts are equally applicable to liquid lines. NACE Task Group (TG) 315 is currently drafting a proposed Standard Recommended Practice entitled "Liquid Petroleum Internal Corrosion Direct Assessment Methodology for Pipelines.".

The specific concern of ICDA is the accumulation of water in the pipeline. The key assumption is that the examination of the pipeline at locations where water would accumulate provides the data that describe the condition of the line at points downstream. The indirect inspection aspect of ICDA uses flow modeling to identify locations where liquid is likely to accumulate corresponding to the locations where pipeline internal corrosion is likely to occur. The model for predicting corrosion susceptibility is based on the gas composition, water chemistry, bacteria, and fluid velocity. These corrosion rate determining factors act independently. The predicted susceptible locations are then subjected to direct examination using such techniques as ultrasonic and radiographic inspection.

One or two locations are excavated. If a corroded condition is identified, mitigation would consist of the combination of scraper/ intelligent pigging and chemical treatments including corrosion inhibitors, biocides, and/or oxygen scavengers. In most cases, the pipes are not cut.

2.4.4.1 ICDA Direct Examination Step: Ultrasonic (UT) Technique

Ultrasonic testing is an inspection tool normally used to measure thickness losses, due to internal corrosion, for the purposes of structural integrity pressure calculations. For direct examination purposes, grid arrays of ultrasonic transducers having two rows of ten transducers each, are arranged next to each other and attached horizontally to the outside of a pipeline in the 6 o'clock position at the excavated location. The number of the 2 x 10 grids used would depend on the extent of the suspected thickness loss. Indeed, it is possible to use only one 2 x 10 grid and move it systematically to inspect the entire exposed location. The data from each transducer in the grid(s) is statistically analyzed to monitor the average general corrosion rate and the increases in the aerial extent of corrosion. The transducers in this case would have a broader beam enabling the inspection of a wider area, but the resolution of each transducer would be about +/-2 mil (where a mil is 0.001 inch). On the other hand, single high resolution UT transducers do have resolutions as low as 0.1 mil, which is quite comparable with probe monitoring.

If significant corrosion is found, it could be a basis for pipe replacement or pipe repair.

2.4.4.2 ICDA Direct Examination Step: Radiography Technique

Radiography testing is also an inspection technique used for thickness measurements at specific intervals. In operation, the X-ray source is located at the 12 o'clock position and the film at the 6 o'clock position, both on the exterior surfaces at the excavated location. As in the ultrasonic measurements, if significant corrosion is determined to have taken place, it could be a basis for pipe replacement or pipe repair. The goal is to ensure reliability.

2.4.4.3 ICDA Post Assessment Step

The post-assessment phase of ICDA determines the level of effectiveness of the process and is used to schedule the next assessment. The goal is to insure reliability of production and avoidance of losses.

2.4.5 External Corrosion

The presence of external pipeline corrosion depends on the following factors:

- Pipe-to-soil potential
- Soil resistivity
- Soil type and composition
- Soil pH
- Groundwater composition
- Coating type
- Coating condition
- Electrolyte pH
- Pipe temperature

- Corrosion products analysis
- Corrosion defects
- Weld seam type
- Wall thickness measurements

For the purposes of integrity management, the applicable direct inspection method is external corrosion direct assessment (ECDA).

2.4.5.1 External Corrosion Direct Assessment (ECDA)

ECDA is a proactive structured process that seeks to improve pipeline safety by assessing and reducing the impact of external corrosion. It is a cost-effective integrity management complement, and sometimes an alternative, to the in-line inspection (ILI) technique and hydrotesting. This is because many transmission pipelines are not "piggable" for a variety of reasons. Also, many practical factors impede the use of hydraulic testing. ECDA is more mature than ICDA and SCCDA; nonetheless its scope is limited compared to those of ILI and hydrotesting. NACE SP0502 addresses the ECDA process.

An important concern of ECDA is the presence of holidays and other external coating anomalies. The key assumption is that the examination of the pipeline at these coatings-effected locations would provide the potential areas where pipeline external corrosion may have occurred, is occurring, or will occur. ECDA determines CP effectiveness and compliance, AC/DC interference, electrical/geologic current shielding, current attenuation, foreign contacts, and extent of mitigation requirements.

The indirect assessment aspect of ECDA uses the following indirect inspection tools:

- Close interval potential survey (CIPS)
- Direct current voltage gradient (DCVG) survey
- Alternating current voltage gradient (ACVG) survey
- Pearson survey

- AC current attenuation (ACCA) survey (an electromagnetic tool)
- Soil resistivity/conductivity survey

Two indirect inspection techniques are required to be used at grade or above grade for each ECDA region, but the choice of the specific tool depends on the applicability of the technique to the specific pipeline segment. Table 2.10 presents the NACE SP0502 guidelines for selecting indirect inspection techniques.

The signals from the integrated survey results provide ample indications to enable site selection for calibration digs (an exploratory excavation or bell holes to prioritize the size or severity of the corrosion conditions). The pipe is excavated for direct examination of condition in terms of defects, coatings adhesion, SCC, MIC, and the overall soil environmental situation including electrolyte, pH, resistivity, and potential. For initial ECDA applications, at least two locations are excavated. This step includes categorizing indications, root cause analysis, evaluating remaining strength, determining the need for repair or corrosion mitigation, in-process evaluation, classification criteria assessment, reclassification and re-prioritization of “immediate,” “scheduled,” and “monitored,” indications.

The last step of ECDA, post-assessment, determines the pipeline’s remaining life, which becomes the basis for defining the re-assessment interval. This step allows for retrospection, feedback, continuous assessment of ECDA effectiveness, and record keeping.

Table 2.10: ECDA Tool Selection Matrix

Conditions	Close-Interval Survey (CIS)	Current Voltage Gradient Surveys (ACVG and DCVG)	Pearson [7]	Electro – magnetic	AC Current Attenuation Surveys
Coating holidays	2	1, 2	2	2	1, 2
Anodic zones on bare pipe	2	3	3	3	3
Near river or water crossing	2	3	3	2	2
Under frozen ground	3	3	3	2	1, 2
Stray currents	2	1, 2	2	2	1, 2
Shielded corrosion activity	3	3	3	3	3
Adjacent metallic structures	2	1, 2	3	2	1, 2
Near parallel pipelines	2	1, 2	3	2	1, 2
Under high-voltage alternating current (HVAC) overhead electric transmission lines	2	1, 2	2	3	3
Shorted casing	2	2	2	2	2
Under paved roads	3	3	3	2	1, 2
Uncased crossing	2	1, 2	2	2	1, 2
Cased piping	3	3	3	3	3
At deep burial locations	2	2	2	2	2
Wetlands (limited)	2	1, 2	2	2	1, 2
Rocky terrain/ rock ledges/ rock backfill	3	3	3	2	2

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

(7) J. M. Pearson, "Electrical Instruments and Measurement in Cathodic Protection," CORROSION 3, 11 (1947): p. 549:

1 = Applicable: Small coating holidays (isolated and typically<600mm^2 [1 in.^{2}]) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.

2 = Applicable: Large coating holidays (isolated or continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

3 = Not Applicable: Not Applicable to this tool or Not Applicable to this tool without additional considerations.

2.5 Stress Corrosion Cracking

Stress corrosion cracking direct assessment (SCCDA) provides an assessment process for detecting the potential for the occurrence of SCC. Also useful is the SCC prediction model, which has a 44% accuracy in predicting the location of SCC. Other methods that could provide continuous "early detection" assessment of SCC include the consideration of the key issues that influenced the occurrences of recorded catastrophic SCC failures. This must take into account all the anions and cations known to cause pitting corrosion in carbon and alloy steel namely:

- Carbon dioxide content
- Total alkalinity of the soil
- Carbonate and bicarbonate content of the soil
- Chloride content
- Sulfate content
- Nitrate ion content
- Pipe temperature
- CP condition
- Hydrogen sulfide content
- Dissolved oxygen content

2.5.1 Stress Corrosion Cracking Direct Assessment (SCCDA)

SCCDA is a proactive structured process that seeks to improve pipeline safety by assessing and reducing the impact of SCC. Like ICDA and ECDA, it is a cost-effective integrity management complement to the in-line inspection (ILI) technique and hydrotesting. NACE Standard SP0204 is the key reference for near-neutral-pH SCC and high-pH SCC. The comprehensive SCCDA process is illustrated by Figure 2.24. The process includes visual and physical inspection, electrolyte analysis, metallographic analysis, ultrasonic inspection, and various magnetic particle inspection techniques.

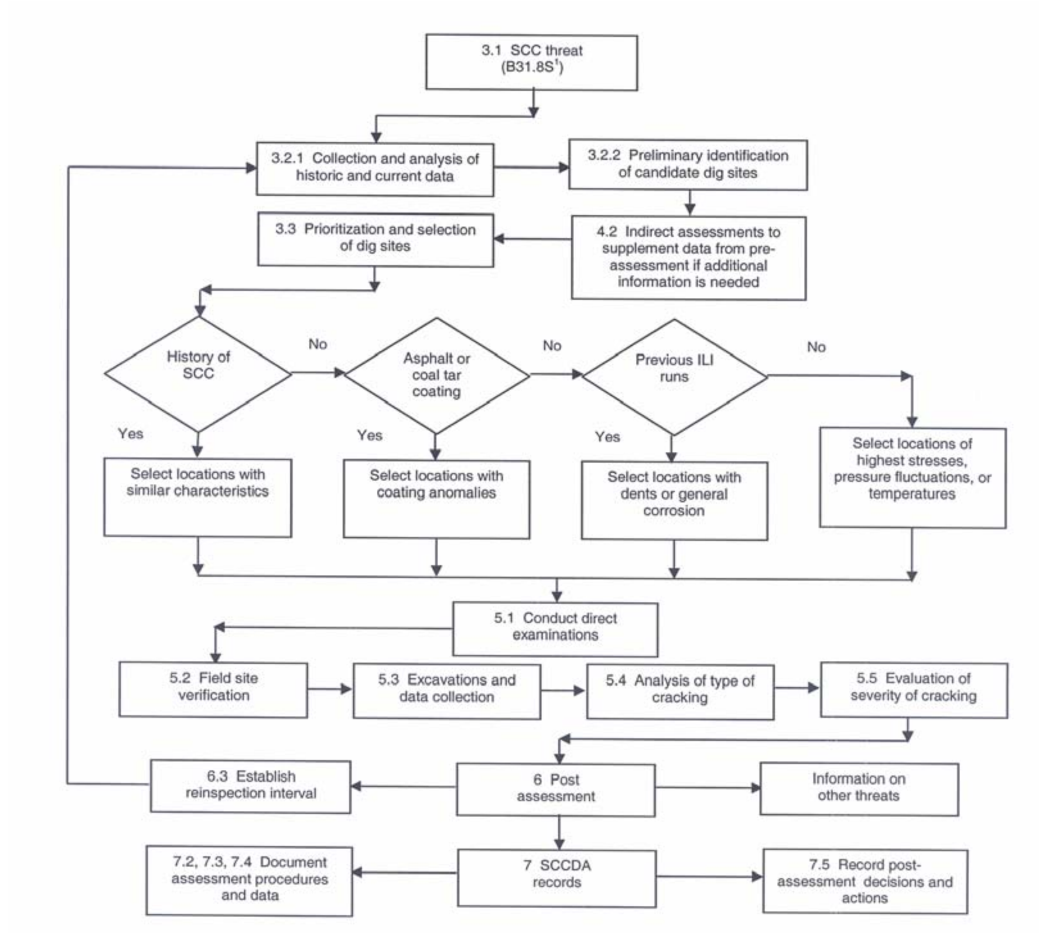


Figure 2.24 A Flow Chart for SCCDA Process
(numbers refer to the paragraph numbers in NACE Standard SP0204)

2.6 Corrosion Monitoring Methods

2.6.1 Internal Corrosion

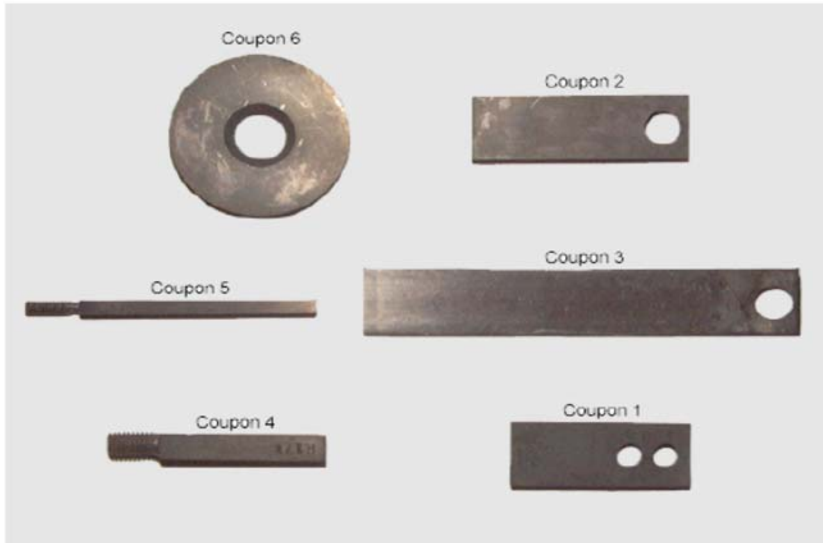
Corrosion monitoring is the generally recognized tool for long-term detection and trending of internal corrosion in oil and gas operations. Cost-effective monitoring includes the use of a series of access fittings for a combination of corrosion coupons to obtain pitting and general corrosion rates for long-term corrosion trending as well as electronic probes for short-term corrosion trending. To monitor the possible presence of sessile bacteria, biostuds and/or coupons are used. Monitoring systems sometimes include the use of grid arrays of ultrasonic transducers attached to the outside of the pipelines.

Generally, production wells and flowlines should be monitored continuously. Pipelines should be monitored at 45–180 day intervals. Each well should be monitored at the 6 o'clock position of the downcomer and each flowline at the 6 o'clock position just before the manifold. Major pipelines should be monitored at several 6 o'clock positions of the horizontal section.

The following are monitoring techniques.

2.6.1.1 Coupons

Weight-loss coupons are the most widely used for monitoring pipelines in oil and gas operation. It is an intrusive method that can be used on pipelines with appropriate access fittings. The coupons are flat or cylindrical, manufactured from low carbon steel such as Grade 1020 (UNS G10200), with factory-stamped identification numbers, specific weights, and are supplied with appropriate electrical isolation from the stainless steel holders. Different strip coupons are made for corrosion (metal loss or pitting) monitoring, scale deposit monitoring, and a pre-stressed variety is available for assessing the indications of stress-corrosion-cracking. Figure 2.25 illustrates six types of corrosion coupons. Figure 2.26 illustrates two types of coupon mounts.



- Coupon 1 – (1/8" T x ½" W x 1-1/4" L, X-42)
- Coupon 2 – (1/8" T x ½" W x 1-1/2" L, B Grade)
- Coupon 3 – (1/16" T x 3/16" W x 3-1/32" L, 1018)
- Coupon 4 – (3/16" T x 3/16" W x 1-1/2" L, X-42)
- Coupon 5 – (1/8" T x 1/8" W x 2" L, 1018)
- Coupon 6 – (Flush-mounted, 1/8" T x 1-1/4" D, 1018).

Figure 2.25 Types of Coupons

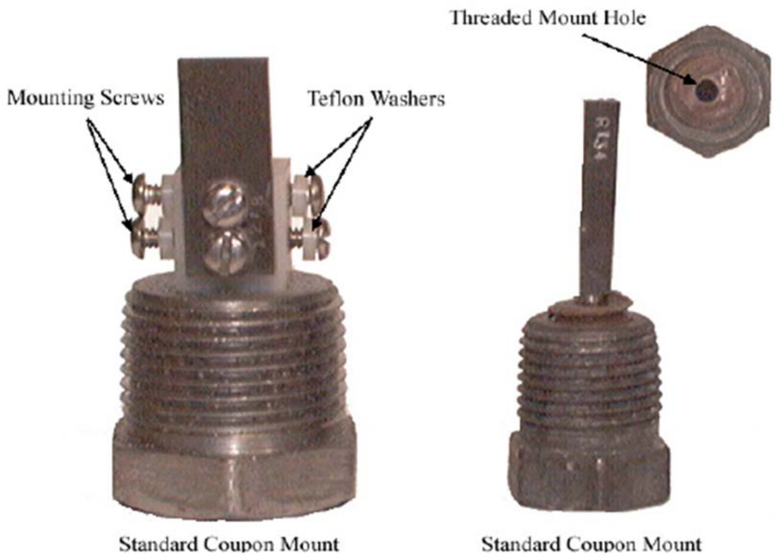


Figure 2.26 Types of Coupon Mounts

Coupon location is decisive in ensuring the assessment of the fluid corrosivity. Three-inch strip coupons are generally used for single phase flow and when the flow velocities are low. The shorter two-inch variety is used when the flow rate is high with the possibility of erosion-corrosion and/or flow-induced fatigue. Flush disc coupons are made for flush mounting in the bottom of pipelines and transfer lines. Multidisc coupon systems are used for multiphase systems, exposed to the water. They are also used for emulsions and dispersed water services.

The corrosion data generated from the coupon, post-immersion, consist of corrosion rates, pit density, visual records of the type of corrosion attack, photographic details of the morphology of the attack, corrosion products analysis, and/or the culture of microbiological metabolic deposits.

Corrosion rates (CR) are normally calculated from the measured weight loss as follows:

CR in mils per year = [(weight loss in grams)(22,300)/(area in square inches) (metal density in grams/cm^3)].

The degree of pitting can be assessed from the calculation of the pitting rate as follows:

Pitting rate in mils per year = [(maximum pit depth in mils)(365)/ days of exposure].

When using coupons, it must be noted that the results would be inconsistent if the coupon surface is coated with paraffin or oil. Short-term exposure may also give misleading results.

2.6.1.2 Electrical Resistance (ER) Probes

Electrical resistance (ER) probes are used to obtain the fluid corrosion rates from consecutive measurements of the resistance of a wire, strip, or tube wall as a function of time. The cumulative metal loss is determined through the increasing electrical resistance of a metal sample as its cross-sectional area is reduced by corrosion since the last probe reading.

Temperature and other effects are essentially subtracted through the use of a "control" (a second protected probe element within the configuration). However, conductive corrosion products deposited on the element will interfere with the calculations as well as interfere with the corrosion on the pipe surface. Note that pitting rates cannot be inferred from ER readings.

There are five different types of probe elements, namely: wire loop, capillary tube, cylinder tube, spiral wound strip, and flush mounted probes. Spiral wound strip probes are susceptible to bridging by iron sulfide and are not recommended for use in sour service. The schematics in Figure 2.27 below represents a typical ER probe.

High sensitivity ER probes, in conjunction with a data logger, provide improved compensation for temperature and electronic noise reduction and their response time could be comparable to that of some LPR probes. The high resolution probes are normally used in flowlines with very active corrosion immediately adjacent to the inlet manifold. They also find applications in assessing the effectiveness and efficacy of new corrosion inhibitors.

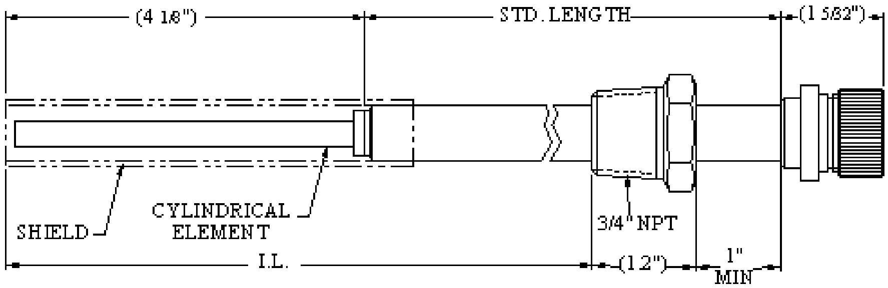


Figure 2.27 ER With Cylindrical Element, Fixed Length With ¾ NPT Pipe Plug

2.6.1.3 Linear Polarization Resistance (LPR) Probes

LPR provides "real-time" instantaneous general corrosion rate measurements of an electrochemically conductive fluid such as water with dissolved ions. The basic designs consist of either two or three electrodes, whereby the fixed potential difference between the electrodes generates a current which is proportional to the general corrosion rate. Figure 2.28 illustrates an example of a three-electrode LPR.

The determination of the corrosion rate involves the measurement of the current required to change the electrical potential (+/- 10 mV) of a corroding specimen in an electrochemically conductive fluid. It does not provide pitting corrosion rates. LPR probes are susceptible to fouling by iron sulfide. They cannot be used in hydrocarbon fluid, which would coat the probe. They can also be used for measuring the corrosivity of electrochemically conductive fluid in soil.

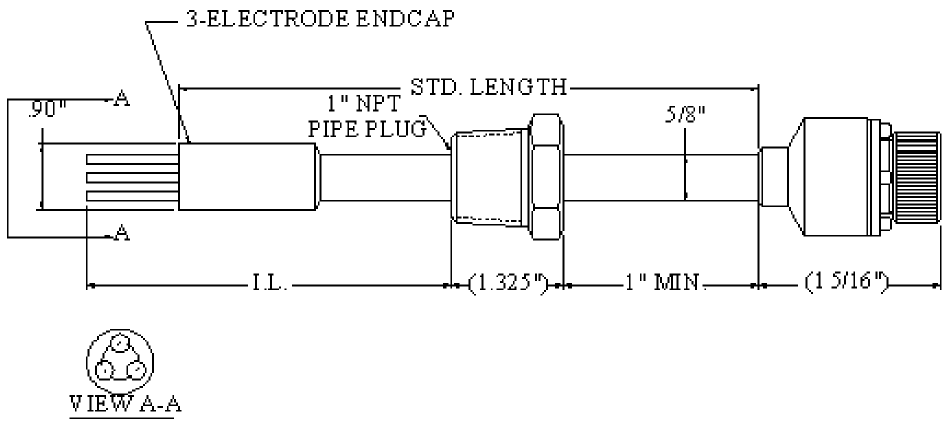


Figure 2.28 Three-Electrode LPR with Fixed length and a 1-Inch NPT Pipe Plug

2.6.1.4 Galvanic Probes

Galvanic probes are the monitoring instruments of choice for dissolved oxygen in water. The effect of dissolved oxygen on corrosion depends on temperature and the fluid dynamics, both of which are reflected in the sensitivity of the probe. The probe is rugged enough to withstand the flow dynamics in seawater treatment plants and various water-handling facilities for effluent water, disposal water, firewater, brackish water, and hydrostatic test water. It is excellent in detecting air leaks in water systems.

A typical galvanic probe consists of a bimetallic couple, usually brass and steel, and a zero resistance ammeter (ZRA), which measures the current generated when the probe is placed in the electrochemically conductive fluid. Because galvanic probes only measure current, they do not give an accurate measure of corrosion rate since the current measured by ZRA depends on the relative area of the anode to the cathode plus other factors.

2.6.1.5 Hydrogen Probes

Hydrogen probes are used for detecting and monitoring atomic hydrogen, a corrosive by-product in sour service that is responsible for HIC, SOHIC, HE, and/or SCC. It is used extensively in systems containing H_2S and sometimes in systems containing CO_2. One type consists of a hollow tube sealed at one end and equipped with a pressure-sensing device on the other. Figure 2.29 illustrates a hydrogen probe with a retractable packing gland assembly.

There are three types of hydrogen probes. In the first type, the pressure-measuring device uses a membrane attached to a pressure gauge or transducer to accumulate the diffused hydrogen. In the second type, the pressure-measuring device uses the vessel wall as its membrane, and the third type utilizes electrochemical devices to measure the ionic current created by the hydrogen permeation into the cell. Hydrogen probes have proved invaluable in trending corrosion in sour service and are not compromised by iron sulfide fouling nor iron oxide bridging. However, these types of probes do not function in the presence of oxygen, which combines with hydrogen to form water.

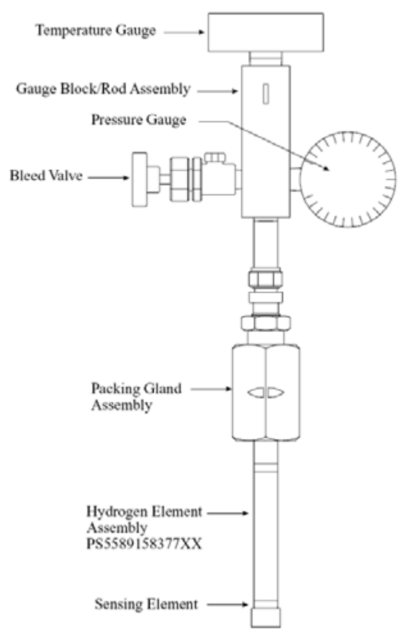


Figure 2.29 Hydrogen Probe With Retractable Packing Gland Assembly

2.6.2 Chemical Methods of Corrosion Monitoring

Laboratory analyses provide an authentic means of corrosion monitoring. This is based on the collection and analysis of samples of liquids, gases, sludge, solids and corrosion products from the inside of the pipeline. Wet chemistal methods and various analytical techniques are used for this purpose. Chemical monitoring methods involve the analysis of chemical or ionic entities that provide continuous "early detection" assessment of internal corrosion including:

- Dissolved iron analysis
- Manganese analysis
- Corrosion product analysis
- Analysis of bottom sediment and water (BS&W)
- Full water analysis
- Water content (water cut)
- Analysis of solids and sludge from "pig" receiver
- Analysis of total dissolved solids (TDS)
- Hardness analysis
- Turbidity
- Conductivity
- pH
- Microbial collection and analysis
- Total organic acid analysis
- Dissolved carbon dioxide analysis
- Carbonate, bi-carbonate, and hydroxide analysis
- Alkalinity
- Glycol analysis
- Acid gas content
- Gas dew point
- Dissolved hydrogen sulfide analysis
- Dissolved oxygen analysis
- Oxygen scavenger residual
- Corrosion inhibitor residuals
- Electrolyte pH analysis
- Chloride analysis
- Sulfide analysis
- Sulfate analysis
- Sulfur analysis

2.6.3 Ultrasonic (UT) Monitoring

Ultrasonic technique is classified as an inspection tool since it is normally used for spot thickness losses at inspection intervals to calculate structural integrity pressure. It measures wall thickness changes after the damage has already occurred. Because of this, it is used principally to complement other intrusive monitoring methods or when the installation of intrusive monitoring devices is not possible.

Typically, 2 x 10 grid arrays of ultrasonic transducers would be permanently attached horizontally to the outside of a pipeline at the 6 o'clock position near the end. The data from each transducer can be statistically analyzed to monitor the average general corrosion rate and the increases in the aerial extent of corrosion as a function of time. Compared to the use of coupon or internal probes, such a resolution is poor indeed. On the other hand, single high-resolution UT transducers do have resolutions which are quite competitive with probe monitoring.

Comparing measurements at 90–180 day intervals provides an assessment of any corrosion trend. Such information assists in making decisions and the necessary planning to target the required corrosion mitigation measures; this ensures reliability.

2.6.4 Radiographic Monitoring

Radiography technique is also classified as an inspection tool; it is normally used for thickness measurements at inspection intervals. It measures wall thickness changes after damage has already occurred. Because of this, it is used principally to complement other intrusive monitoring methods or when installation of intrusive monitoring devices is not possible.

Real-time radiography includes the use of a video imager which displays the image on-line. Comparing measurements at 90–180 days apart provides an assessment of any corrosion trend. Such information assists in making the decisions and the necessary planning to target the required corrosion mitigation measures; this ensures reliability of production and avoidance of losses.

2.7 External Corrosion

External corrosion monitoring is a post-assessment process of ECDA. The monitoring methods for external corrosion include external weight-loss coupons, pitting corrosion coupons, external LPR, and external corrosion products analysis of the soil adjacent to the pipeline.

Pre-stressed coupons are also available to assess the conditions conducive to stress corrosion cracking. Monitoring methods can also be used for testing the soil environment surrounding the pipe. This includes consideration of the following chemical, ionic, and electrical characteristics that could provide continuous "early detection" assessment of external corrosion:

- Pipe-to-soil potential
- Soil chloride ion content
- Soil moisture content
- Soil oxygen content
- Soil permeability
- Microbiological activity in the soil
- Redox potential of the soil
- Sulfate ion content of the soil
- Sulfite ion content of the soil
- Total acidity of the soil
- Total alkalinity of the soil
- Carbonate and bicarbonate content of the soil
- Drainage characteristics of the soil
- Soil resistivity/ conductivity
- Soil type, texture, and composition
- Under-film pH
- Groundwater composition
- Total hardness of the groundwater

- Soil composition changes that could create long-line corrosion
- Electrolyte pH
- Pipe temperature
- Corrosion products analysis
- Corrosion defects
- Stray current
- Seasonality of moisture content variation
- Incidence and extent of corrosive substance spillage
- Incidence and extent of pollution

2.7.1 Stress Corrosion Cracking

The basic forms of corrosion that serve as precursors to SCC are (1) localized pitting corrosion, (2) intergranular corrosion (IGC), (3) hydrogen embrittlement (HE), and (4) de-alloying cleavage. The methods found effective to monitor these forms of corrosion are equally effective for monitoring SCC. These include some of the methods described under ECDA. In particular, the use of hydrogen probes for detecting and trending corrosion in sour service provide continuous "early detection" for HIC, SOHIC, HE, SSC, and/or SCC.

2.8 Corrosion Mediation Methods

The dictionary defines mediation as "intervention between conflicting parties to promote a compromise..." In principle therefore, mediation happens after a conflict has started, not before. In the context of corrosion, the "conflict" is between an inanimate "steel" and its "hostile environment." Carbon and alloy steel materials must be used in hostile oilfield environments which cause them to corrode. What should be done to promote a "compromise;" e.g., minimize the "veracity" of corrosion after it is discovered to extend the useful life of the pipeline? In this sense, all "corrosion control methods" are also "corrosion mediation methods." Before the appropriate mitigation program is selected, the operator must first determine the corrosion rate (or severity) and the corrosion mechanism. It is important to ensure that the monitoring program reflects the corrosive environment before selecting a strategy. It is also important to recognize that an inappropriate choice or a misapplication of mitigation measures may inadvertently cause further corrosion.

Based on the above definition, the six techniques discussed earlier in this chapter (Section 2.2 "Overview of Corrosion Control Methods" on page 23) are applicable as mediation techniques and will now be discussed in relative detail.

2.8.1 Material Selection

2.8.1.1 Ferrous Alloys – Carbon Steels

Steel is primarily an alloy of iron and carbon with components of pure iron and iron carbide, the shape and distribution of which result from the heat treatment of the steel. Carbon steels (up to 2% carbon) have residual quantities of other elements with as much as 1.65% manganese and 0.6% silicon without being considered alloy steels. Sulfur and phosphorus are residual elements. Alloyed steels have significant quantities of alloying elements, such as manganese, silicon, copper, aluminum, boron, chromium, cobalt, molybdenum, nickel, niobium, titanium, tungsten, vanadium, zirconium, or any other alloying element needed to obtain a desired effect. Alloy steels containing at least 10.5% chromium are classified as "stainless steels."

There are well over 100 alloy compositions that meet the basic definition of stainless steel. Each of these is corrosion resistant in certain specific environments, but no single stainless steel fits all the requirements in all applications. Stainless steels do corrode when the application is wrong and fail mainly from pitting and cracking. However, for stainless steel piping designed for use where high temperature sulfidation is expected (based on the temperature and the sulfur content or the H_2S content), the theoretical corrosion rate allowance is about 0.03 mm/yr.

2.8.1.2 Ferrous Alloys – Austenitic Stainless Steels

Austenitic stainless steels contain 18-25% chromium, 8-20% nickel, and other elements that are added for specific purposes. These non-magnetic materials are characterized by high corrosion resistance, low strength and cannot be hardened by heat. The "300" series are the most common in the oil field. They consist of 304 (UNS S30400), 316 (UNS31600) that contains molybdenum for increased pitting resistance, 303 (UNS30300) for free machining, and the 347 (UNS34700) stainless steel that is stabilized for welding and corrosion resistance. There is a low carbon grade (<0.03% carbon) stainless steel which possesses improved resistance to inter-granular attack. Three super austenitic stainless steels containing between 50-75% iron are currently available: AL-6XN (UNS N08367), 904L (UNS N08904), and 20-Mo6 (UNS N08026). The super austenitic stainless steels UNS N08904 and UNS N08028 are resistant to H_2S in environments with higher than 0.1 bar (1.45 psia) H_2S partial pressure.

2.8.1.3 Ferrous Alloys – Martensitic Stainless Steels

Martensitic stainless steels can be hardened by heat. They contain 12-18% chromium, 0.08-1.1% carbon, along with other elements added for special purposes. The "400" series are the most common in corrosive well service, valves, and wellhead equipment. Included is 410 (UNS S41000) containing 13% chromium, which is used for tubes, valves, and wellhead equipment. UNS S41000 is the basic martensitic stainless which achieves high mechanical properties after heat treatment. It has good impact strength, plus corrosion and scaling resistance up to 1200^o F (649^o C). The 420 (UNS S42000) is a forging material that also contains 13% chromium.

2.8.1.4 Ferrous Alloys – Ferritic Stainless Steels

Ferritic stainless steels cannot be hardened by heat treatment. They contain 13-27% chromium and <0.08% carbon. Although they are characterized by good corrosion resistance and high temperature properties, they have limited application in oil and gas service.

2.8.1.5 Ferrous Alloys – Duplex Stainless Steels

Duplex stainless steels can be cold-worked to gain strength as high as 110-125 ksi (760-860 MPa). They contains 20-29% chromium and 3-7% Ni. Their microstructures are a mixture of austenite and ferrite and, when annealed, they are more resistant to H_2S than their cold-worked equivalent. They are used in oilfield applications such as downhole tubing, flowlines, facilities piping, and pressure vessels. UNS S31803 (2205 alloy) is a duplex stainless steel resistant to H_2S in environments with less than 0.1 bar (1.45 psia)

H_2S partial pressure, but is susceptible to stress corrosion cracking above that limit. However, super duplex UNS S32760 is resistant to H_2S in environment with higher than 0.1 bar (1.45 psia) H_2S partial pressure. Both are resistant to CO_2.

2.8.1.6 Ferrous Alloys – Cast Irons

Cast iron is a low cost, low ductility, and low tensile strength member of the ferrous alloy family. It contains free carbon in its microstructure because its carbon content exceeds its solubility limit in iron. There are four important varieties of cast iron which differ in composition, heat treatment, microstructure and mechanical properties. They are gray, white, malleable, and ductile iron. Because of their diminished ductility, cast irons find little application in oil and gas service.

2.8.1.7 Non-Ferrous Alloys – Nickel-Based Alloys

A rather expensive non-ferrous alloy that finds application in very severe corrosive service contains more than 50% nickel, a significant amount of chromium, and the remainder iron. The most commonly in oil and gas applications are: (1) alloy 625 (UNS N06625), (2) Inconel 825 (UNS N08825), and (3) alloy C276 (UNS N10276). Inconel 825 is resistant to H_2S in environments with higher than 0.1 bar (1.45 psia) H_2S partial pressure.

2.8.1.8 Non-Ferrous Alloys – Copper-Based Alloy

The nickel-copper alloy UNS N05500 (K-500) has excellent corrosion-resistant characteristics, and enhanced strength and hardness after precipitation hardening with aluminum and titanium. Cold working prior to precipitation hardening further strengthen it. It consists of 65.5% nickel, 29.5% copper, 2.7% aluminum, and 0.6% titanium.

2.8.1.9 Non-Metals – Thermosetting Composites

This class of minerals is variously referred to as fiberglass-reinforced plastic (FRP), glass-reinforced epoxy (GRE), reinforced thermosetting resin (RTR), or reinforced thermosetting resin pipe (RTRP). The most common thermosetting resins are epoxy and polyester. The composites are used as tubulars, tanks, integral fittings in water handling services, and as sucker rods.

Thermosetting composites are completely resistant to internal and external corrosion but the resin is susceptible to certain specific solvents.

2.8.1.10 Non-Metals – Thermoplastics

Thermoplastic materials consist of polyvinyl chloride (PVC), high density polyethylene (HDPE), low density polyethylene (LDPE), and polypropylene (PP). These materials are used as low-pressure line pipe (flowline, gathering line, and salt water lines), internal liners for steel pipelines (new or reclaimed), and as chemical storage drums for various chemicals. Thermoplastics are completely resistant to internal and external corrosion.

2.8.1.11 Non-Metals – Elastomers

These polymeric materials are used in downhole sealing operations either to minimize or eliminate the entry of oil field fluid. The three basic seal types are (1) radial compression seals (O-rings, T-seals); (2) axial compression seals (packer element seals); and (3) pressure energized seals (V-packing stacks). The elastomers used in each of these seal types are: high density nitrile (HSN), fluoroelastomer (FKM, Viton), tetrafluoroethylene-propylene (FCM, Aflas); and perfluoroelastomer (FFKM, Chemraz or Kalrex). Applications which need back-up materials utilize the following high performance thermoplastics: molybdenum disulphide reinforced Teflon (FPM), polyphenylene sulphide (PPS) and polyetheretherketoine (PEEK). Other elastomers appropriate for oilfield applications as O-rings or tank liners are polychloroprene (neoprene), butyl rubber, ethylene-propylene-diene-monomer rubber (EPDM), and nitrile rubber (Buna-N).

2.8.1.12 Cementitious Materials – Cement and Concrete

These materials are used for reinforced concrete offshore structures and the foundation for pumping units, injection pumps, and compressors. Applications also include cement linings for tank bottoms, internal pipe coatings, and secondary containment basins. Although the materials are resistant to ordinary water, corrosion of the reinforcing rebar leads to concrete cracking and spalling. Such failure can be mitigated by coating the rebars with fusion bonded epoxy (FBE), applying cathodic protection, or by using 304L or 316L stainless steel rebars.

2.8.2 Protective Coatings

The most widely used coatings, primary resins and their use is detailed in Table 2.11. Thin, liquid applied coatings are classified as atmospheric coatings, immersion coatings, and underground or buried coatings. Buried and immersed structures are often protected from corrosion by protective coatings in conjunction with cathodic protection. Coatings can be used as environmental barriers to isolate the steel structure from the corrosive environment (the electrolyte), thus reducing the current demand for cathodic protection systems. Coatings used as environmental barriers include epoxies, polyurethanes, polyolefins, tapes, and waxes.

After coating application, thin-film equipment coatings range in thickness from 5-8 mil (0.13-0.2 mm) but thin-film pipeline coatings range in thickness from 20-200 mil (0.5-2.5 mm). On the other hand, thick-film production equipment coatings range in thickness from 12-25 mil (0.3-0.6 mm) but thick film pipeline coatings are characterized by thicknesses that are higher than 100 mil (2.5 mm).

Table 2.11: Primary Resins and the Typical Application of Widely Used Coatings

Primary Resin	Typical Application
Acrylics	External
Alkyds and modified alkyds	External — weathering
Chlorinated rubber	External — chemical resistance
Coal-tar Epoxy	Immersion
Epoxy-catalyzed (2-part Epoxy)	Immersion
Epoxy ester (1-part)	External
Phenolics (baked)	Internal — vessel, tubing
Epoxy-modified Phenolics	Internal — vessel, tubing
Oil-modified Phenolics	External — marine
Polyester and fiber reinforced polyesters	Immersion — tank and vessel
Silicones	High temperature
Urethanes — oil modified	External weathering
Vinyl	External and Internal
Zinc-rich	External — primer

Four curing methods are generally used. Atmospheric coatings are air-dried. Forced cure coatings, used for the interiors of tanks and vessels, are dried in heated air up to 175°F (80°C). Epoxies, phenolics vessel and internal tubing coatings are baked in an oven at temperatures around 400°F (205°C). Fusion-bonded epoxy (FBE) coatings used for pipes, valves, and other equipment are applied as solid powder to heated metal surfaces where they fuse. Field structures are normally coated using spray, brush or roller application. The conventional spray atomizes the paint or coating with compressed air and the airless spray atomizes by a pressure drop at the spray nozzle.

With all coating systems, the surface preparation is a critical step. The pipe surface must be cleaned properly to remove all salts, oil, grease and dirt. Blast cleaning is normally recommended using any of the following NACE procedures:

- White metal blast cleaning (NACE No. 1/SSPC-SP 5)
- Near-white metal blast cleaning (NACE No. 2/SSPC-SP 10)
- Commercial blast cleaning (NACE No. 3/SSPC-SP 6)
- Brush-off blast cleaning (NACE No. 4/SSPC-SP7)

The surface profile must provide the necessary anchor pattern for the specific coating thickness in accordance with the following:

Dry Film Coating Thickness Anchor Pattern

125-200 microns (5-8 mils) 20-25 microns (1-2 mils)

200-500 microns (9-20 mils) 50-75 microns (2-3 mils)

>500 microns (>20 mils) 75-125 microns (3-5 mils)

Perhaps the most critical and certainly the most expensive part of the pipeline coating process is the actual application of the protective coating. Generally, all coatings should be applied to the proper thickness and cured under conditions recommended by the manufacturer. The coating design must include some or all of the following precautions:

- Elimination of sharp corners
- Butt welding instead of lap welding
- Removal of weld splatter
- Continuous welds (no skid welding)

- Designs that will not collect or hold water and debris
- Drainage in recessed zones
- Remove roughness and surface defects by grinding
- Round all corners
- Eliminate hard-to-reach places
- Ensure all surfaces are accessible
- Ensure a continuous and even surface to facilitate complete bonding
- Eliminate intricate construction that creates crevices
- Remove mill scale from the surface
- Provide easy access to coat and inspect tanks, vessels, or piping

Inspection is also critical to ensure that protective coatings perform the corrosion prevention duties as they should. Coatings must be inspected by a qualified coating inspector using the appropriate inspection tools such as film thickness gauges and holiday detectors. The critical coating inspection timing is as follows:

- Prior to blast cleaning
- After blast cleaning
- After each coat is applied
- After final cure
- Final completion inspection

The regulatory and industry accepted protective coatings standards, published by NACE International are:

- NACE SP0178, "Fabrication Details, Surface Finish Requirements, and Proper Design Considerations for Tanks and Vessels to Be Lined For Immersion Service"
- NACE SP0181, "Liquid-Applied Internal Protective Coatings for Oilfield Production Equipment"
- NACE SP0191, "The Application of Internal Plastic Coatings for Oilfield Tubular Goods and Accessories"

- NACE RP0291, "Care, Handling, and Installation of Internally Plastic-Coated Oilfield Goods and Accessories"
- NACE TM0174, "Laboratory Methods for the Evaluation of Protective Coatings and Lining Materials on Metallic Substrates in Immersion Service"
- NACE TM0183, "Evaluation of Internal Plastic Coatings for Corrosion Control of Tubular Goods in Aqueous Flowing Environment"
- NACE TM0185, "Evaluation of Internal Plastic Coatings for Corrosion Control of Tubular Goods by Autoclave Testing"
- NACE TM0186, "Holiday Detection of Internal Tubular Coatings of 250 to 760 µm (10 to 30 mils) Dry-Film Thickness"

2.8.3 Cathodic Protection

2.8.3.1 Galvanic Anodes

As previously shown in Figure 2.17, the four basic components of a galvanic anode CP are (1) the anode, (2) the anode backfill, (3) a means of connecting the anode to the structure, (4) and the structure. Galvanic anode alloys include:

Magnesium anodes are available in two alloys: a high-potential alloy having a nominal corrosion potential of –1.75 V referenced to a copper-copper sulfate electrode and a low-potential alloy having a nominal corrosion potential of –1.55 V referenced to a copper-copper sulfate electrode. Magnesium is normally used in soils and fresh water. The Standard Alloy is used in low-resistivity soils and water, and the High-Potential Alloy provides a higher driving voltage than the standard alloy.

Zinc anodes are also commercially available in two alloys, one for use in soils and the other for seawater applications. Zinc may undergo rapid intergranular corrosion at temperatures above 120°F (49°C). At temperatures above 130°F (54°C) and particularly in the presence of carbonates, zinc can passivate and the potential of the passive film can become more noble than steel, leading to corrosion of the steel. MIL-A-18001 or ASTM B418 Type I is used for salt water and brackish water applications. ASTM B418 Type II high purity is used for underground and fresh water applications.

Aluminum anodes are used primarily in seawater applications and are produced in a variety of alloys, of which the mercury and indium alloys are the most common. The indium alloy has a slightly higher corrosion potential but is less efficient than the mercury-containing alloy. Aluminum is preferred for seawater applications because it has a much lower consumption rate than magnesium or zinc. Aluminum anodes are not used in fresh water, except as impressed current anodes. They are not used underground. An alloy of aluminum-zinc and indium is used as a sacrificial anode on reinforced concrete structures. Aluminum anodes are commonly used in process vessels containing brine. At temperatures above 120°F (49°C), however, the current output may be reduced. Galvalum I™* contains zinc and mercury for use in seawater (*seldom used due to mercury content)*. Galvalum II™* contains zinc and mercury for use in saline mud (*seldom used due to mercury content)*. Galvalum III™ contains zinc and indium for use in seawater, brackish water, and saline mud.

Galvanic anodes are available in a wide range of shapes and sizes for specific applications. Custom shapes and sizes can be made. For marine environments (platforms), dual galvanic anodes can be made with a highly active anode metal casing (e.g., magnesium) on a less active anode core (e.g., zinc). These are used to provide a high initial current density to achieve initial cathodic protection polarization on offshore structures. Once the protection potential is achieved, the less active anode can maintain an adequate cathodic protection polarization.

Galvanic anodes can be attached to the structure either directly by welding or bolting integral straps to the structure, e.g., hull-mounted anodes and bracelet anodes, or by connecting a wire between the anode and structure. If a wire is used, the manufacturer attaches it to the anode. The wire is attached to the structure using a mechanical connection, thermite weld, or other suitable method. The thermite weld is the preferred method since it provides the most reliable connection. The wire should be coated with a dielectric insulation and the connections should be coated.

The efficiency of a galvanic anode depends on the alloy of the anode and the environment in which it is installed. The consumption of any metal is directly proportional to the amount of current discharged from its surface. For galvanic anodes, part of this current discharge is due to the cathodic protection current provided to the structure and part is caused by local corrosion cells on its surface. Anode efficiency is the ratio of metal consumed producing useful cathodic protection current to the total metal consumed. For magnesium, the anode efficiency is generally less than 50%, while zinc has an efficiency of 90%.

The following are among the conditions where galvanic anodes are used:

- When a relatively small amount of current is required
- Usually lower resistivity electrolytes
- For local cathodic protection to provide current to a specific area on a structure. Some pipeline operators install galvanic anodes at each location where a leak is repaired rather than installing a complete cathodic protection system. Such practices may be encountered on bare metal or very poorly coated systems where complete cathodic protection may not be feasible because of cost.
- When additional current is needed at problem areas. Some structures with overall impressed current cathodic protection systems may have isolated points where additional current in relatively small amounts is needed. These requirements can be met with galvanic anodes.
- Poorly coated buried valves
- Interiors of water storage tanks
- Shorted casings that cannot be cleared (to improve potentials in the surrounding area)
- Underground storage tanks
- Isolated sections where the coating has been badly damaged
- Areas where electrical shielding impairs effective current distribution from remotely located impressed current systems
- In cases of cathodic interference, if the conditions are suitable, galvanic anodes can be used at the discharge point to return interfering current.

- To provide protection to structures located near many other underground metallic structures where conditions make it difficult to install impressed current systems without creating stray current interference problems. Galvanic anodes can be an economical choice for a cathodic protection current source under such conditions.
- Galvanic anodes find extensive use in protecting the interior surface of heat exchanger water boxes and other vessels. They are also used within oil heater-treater vessels, depending on the quality of the interior lining and the fluid chemistry and temperature.
- On offshore structures, large galvanic anodes may be used to protect the underwater components.

2.8.3.2 Anode Backfill for Galvanic Anodes

Zinc and magnesium anodes used in cathodic protection applications in soil are sometimes supplied prepackaged with a prepared backfill material in a cloth or cardboard container. The special backfill prevents direct soil contact to reduce localized corrosion of the anode, prevents passivation of the anode caused by reactions with soil salts, provides a low-resistivity environment around the anode, and expands when wet to fill the hole and eliminate air voids. The most common backfill material contains 75% hydrated gypsum, 20% bentonite clay, and 5% sodium sulfate. Zinc anodes can also be packaged in a backfill consisting of 50% hydrated gypsum and 50% bentonite clay. Since zinc anodes are normally installed in low-resistivity soil, it is not necessary to add sodium sulfate to lower resistivity.

2.8.3.3 Impressed Current Anodes

Graphite anodes are used in soils, flowing seawater, and mud. They are practically immune to chlorine attack. Graphite anodes are usually impregnated with a sealer to prevent mechanical failure from gas evolution in pores. Graphite is also brittle. Consumption rates are 0.45 kg/A-y (1 lb/A-y) in seawater, 0.9 kg/A-y (2 lb/A-y) in carbon backfill, and 1.36 kg/A-y (3 lb/A-y) in mud. Graphite anodes are usually available as cylindrical anodes.

Conductive polymer – Carbon is used as filler in polymer materials having a copper core for use as an impressed current anode. This type of anode looks like an insulated wire but the covering is conductive. (Note: this type of anode wire must not be used where dielectrically insulated wire is needed.) This material has a maximum rating of 51 mA/m (16 mA/ft) of material.

Carbon has also been used as conductive filler in water- or solvent-based coatings for application as an anode to protect reinforced concrete structures.

High-silicon cast iron (HSCI) anodes are made of a chemically resistant alloy containing silicon, chromium, and iron. HSCI anodes are commonly used in fresh water, seawater, or underground applications. HSCI is very brittle and forms a SiO_2 film on the surface in underground applications that can increase the resistance of the anode in dry environments. The consumption rate of HSCI ranges from 0.25 to 1 kg/A-y (0.55 to 2.20 lb/A-y).

Lead-silver anodes have been used in seawater applications. The lead under anodic current develops a PbO_2 film that is conductive and prevents deterioration of the lead. The consumption rate of lead-silver alloys is on the order of 0.09 kg/A-y (0.2 lb/A-y).

Lead-platinum anodes – Extruded lead anodes with platinum pins have also been used in seawater applications. The purpose of the platinum pins is to promote the formation of the PbO_2 film.

Mixed-metal oxide (MMO) anodes, also called dimensionally stable anodes, consist of rare earth oxides baked onto a titanium substrate. These anodes were developed for the electrolytic production of chlorine and hypochlorites, but are now used for cathodic protection applications. The consumption rate is on the order of 1 mg/A-y. This anode material is typically available in rod, wire, tubular, or mesh form.

Platinum is used as an anode material when it is either metallurgically clad or plated onto either a titanium or niobium substrate. Titanium and niobium form stable oxide layers when made anodic. These layers are stable up to 12 V in the case of titanium and 90 V in the case of niobium. The consumption rate of platinized anodes is on the order of 6 to 10 mg/A-y. Platinized anodes are available in wire or mesh form. Platinized anodes are subject to rapid deterioration if the breakdown voltage is exceeded or if the environmental conditions surrounding the anode become acidic. Other deleterious factors include the presence of low-frequency AC ripple, current reversal, biofouling, scales, and the presence of certain organic materials. Platinized anodes are most suitable in fresh or salt water applications rather than in underground applications.

Scrap iron or steel can be used as an anode material. In situations where the current requirements are low, scrap iron is readily available, and the anode can be readily replaced, scrap iron might be an economical choice. The consumption rate of iron is 6.8 to 9.1 kg/A-y (15 to 20 lb/A-y). The relatively rapid dissolution rate and difficulty in maintaining the integrity of the connection between the power supply and anode are disadvantages of this material.

Metallized titanium is being tested for use on reinforced concrete structures. The titanium is first sprayed onto the concrete surface using an arc spray technique and then a liquid catalyst is applied to activate the anode.

Thermal sprayed zinc and aluminum alloys have been used as impressed current anodes on reinforced concrete structures. The relatively low current requirement for this type of structure has made the use of zinc and aluminum alloys practical in these applications.

Magnetite is a sintered material made up of Fe_3O_4. It is used in seawater, brackish water, fresh water, and high-resistivity soil. The consumption rate of magnetite is 0.005 to 0.08 kg/A-yr. Magnetite is available in cylindrical form.

Aluminum has also been used as an impressed current anode, primarily in fresh water applications such as water storage tanks. The dissolution rate of aluminum as an impressed current anode is about 4.5 kg/A-y (10 lb/A-y).

Anode Backfill for Impressed Current Anodes

Carbon is used as a backfill material around impressed current anodes for underground CP applications. The purpose of the backfill material is to:

- Reduce the resistivity of the environment surrounding the anode to increase the amount of current the anode can discharge
- Extend the anode surface area, thus increasing the amount of current the anode can discharge
- Reduce consumption of the anode since the carbon becomes the part of the anode consumed before the anode itself

Carbon backfill for cathodic protection purposes is available as calcined petroleum or metallurgical coke, each being the product of its respective industry. Non-calcined carbon is also available, but is not suitable for CP use since it can have too high an electrical resistance.

The typical composition of carbon backfill appears in Table 2.12.

The resistance of carbon backfill is dependent on how well it is compacted. The higher the degree of compaction, the lower the resistance. The size of the carbon particles is important in compaction. A mixture of large and small sizes is advisable to attain good density and low resistance. The size range may be on the order of 0.5 to 12.7 mm (0.02 to 0.5 in.). Finer grade coke is often used for deep anode systems and the particles may range from 0.10 to 1 mm (0.004 to 0.04 in.) in size.

Table 2.12: Typical Composition of Carbon Backfill for Impressed Current Anodes

	Metallurgical	Calcined
Carbon	85%	99%
Ash	8 to 10%	0.1%
Moisture	6 to 9%	0%
Sulfur	1%	
Volatile matter	3%	<0.5%
Density kg/m^3 (lb/ft^3)	730 (45)	875 to 1,200 (54 to 74)

Impressed current anodes for underground applications can be supplied prepackaged in carbon backfill. The carbon backfill and anode are packaged in an individual galvanized steel canister. Carbon backfill for deep anode systems is added during installation of the anode bed by pumping a fluidized mixture of water and carbon backfill to the bottom of the hole and allowing the carbon particles to settle out.

In impressed current CP systems, all wiring and connections must totally isolate the metal from the electrolyte. Unlike a galvanic anode system where exposed wire and connections are protected by the anode, any exposed metal in an impressed current CP system is part of the **anode**. Thus, exposed metal will corrode rapidly. Only cable having approved cathodic protection dielectric insulation can be used. Types of insulation found on CP cables include:

High-Molecular-Weight Polyethylene (HMWPE) – This insulation is commonly used for direct burial cathodic protection installations for both anode and structure wiring. The insulation for cathodic protection cable (type CP) is thicker than standard polyethylene insulation (e.g., THW). HMWPE insulation is not recommended for use in environments containing chlorine, hydrochloric acid, or petroleum hydrocarbons.

Halar/polyethylene is a dual-jacketed layered insulation. The outer jacket (HMWPE) provides mechanical protection for the wire as well as chemical resistance and dielectric insulation. The inner jacket is Halar, which is a thermoplastic fluoro-copolymer which is resistant to chemicals, including chlorine, hydrochloric acid, sulfuric acid, petroleum hydrocarbons, alkalis, and strong oxidizing acids. The temperature range of this insulation is 62°C (144°F) to 121°C (250°F).

Kynar (polyvinylidene fluoride)/modified polyolefin is a dual-jacketed insulation similar to Halar/polyethylene. The outer jacket (HMWPE) provides mechanical protection to the wire as well as chemical resistance and dielectric insulation. It is resistant to chlorine, hydrochloric acid, sulfates, hydrogen sulfides, alkalis, other acids, petroleum-based chemicals, and chlorine gas.

Total encapsulation of splices and connections is required to prevent water from getting into the splice, which will eventually destroy the connection. Encapsulation is achieved using an epoxy resin cast into a mold around the splice, heat-shrink sleeves containing adhesive mastic manufactured for CP purposes, or multi-component wrapped connections. Prior to applying the splicing material, the wire should be thoroughly cleaned to remove greases, oil, and dirt. The wire insulation should be lightly abraded prior to applying the splice. This is one area where a little care will prevent problems later on.

Splices should be avoided if possible, especially in the anode circuit.

2.8.3.4 Impressed Current Power Supply

Unlike galvanic anode systems where the natural potential difference between the anode and cathode provides the driving force for current, an impressed current CP system must be supplied with power from an external source.

Depending on economics, any source of DC power can serve as an impressed current power source and may consist of:

- Transformer-rectifier (rectifier)
- Thermoelectric generators (TEG)
- Solar power
- Wind-driven generators
- Engine driven generators
- Batteries
- Fuel cells
- Closed cycle vapor turbo generator

It is important to ensure that the power source in an impressed current system remains operational and that the cathodic protection system is connected with the proper polarity. The negative (-) terminal of the power source must be connected to the structure and the positive (+) terminal must be connected to the anode bed.

Transformer-Rectifier – The most common type of power supply used for impressed current cathodic protection is a transformer/rectifier, commonly referred to simply as a *rectifier*. A rectifier converts the AC power supply voltage to the required output voltage and then converts it to DC. Rectifiers are either supplied in ventilated cases to allow convective air cooling or are immersed in transformer oil. Rectifiers are normally powered by an AC power system. The basic units of a rectifier consist of:

- AC supply

- Circuit breaker (Thermal Breakers, Magnetic Breaker, and Thermal Magnetic Breakers)
- Transformers
- Rectifying elements (Silicon-Controlled Rectifiers (SCR), Switching-Mode Rectifiers, Pulse Rectifiers, Constant Voltage Rectifiers, Constant Current Rectifiers, Constant Potential Rectifiers
- Meters
- DC output terminals
- Fuses
- Surge protection (*depending on unit)*

The proper connection of a rectifier is CRITICAL and if done improperly can result in catastrophic damage to the structure that is supposed to be protected, resulting in loss of product, structural damage, property damage, environmental damage, or loss of life.

Often the cathodic protection cables are either not identified or are incorrectly identified. It is therefore mandatory to verify the proper connection polarity. This can be accomplished by measuring the structure-to-electrolyte potential near the power source both before and after the source is activated. A shift in potential in the electronegative direction with the power source energized, confirms the correct polarity. For this test the cable connected to the negative terminal of the rectifier should not be used as the test lead for the structure-to-electrolyte potential measurement.

When connecting a rectifier to an AC power supply, the AC supply circuit should be dedicated and separately fused. The rectifier should never share an AC circuit with normally interruptible facilities such as lighting and pumps.

The voltage and current output of the power source should be monitored regularly to ensure that the unit remains operational. Basic rectifier operational data include:

- AC input voltage
- DC output voltage and DC output current

- Tap settings and/or potential set point (if constant potential) or current set point (if constant current)
- Anode-to-structure resistance

Other sources of power are available where AC power is not readily accessible.

Engine Generator Sets – Engine generator sets consist of a fuel-powered engine that drives a generator to provide the AC for the rectifier. The pipeline or a nearby source could supply the fuel. DC generators can be considered but usually require high maintenance.

Thermoelectric Generators – Another alternative energy power supply available for cathodic protection applications is the thermoelectric generator (TEG). Thermoelectric generators convert heat energy directly into electrical energy. A clean fuel such as natural gas or propane is required. They are a relatively low power (wattage) unit and must operate near their optimum load resistance to realize the rated output.

Solar Power Supplies – A solar power supply consists of a solar panel, a charge controller, and a battery system. Specially designed doped silicon semiconductors, which are photosensitive, convert solar energy to electrical energy. These semiconducting devices (photovoltaic cells) produce a voltage by absorbing energy from light photons striking the semiconductor and freeing electrons within the semiconductor. The conversion efficiencies for silicon-based photovoltaic cells are in the range of 8 to 14%.

Wind-Driven Generators – If a sufficient, steady source of wind is available, wind-driven generators are another possible alternate energy source for cathodic protection. These DC generators generally begin producing usable current outputs at wind speeds of about 16 km/h (10 mph) with maximum output achieved at speeds of 40 to 55 km/h (25 to 35 mph). Since the output varies with wind speed, a battery system is required not only as a backup when the wind is flat, but also to provide a constant DC output for the cathodic protection system. The generator output charges a battery system, and the battery system supplies the output cathodic protection current

Due to the high maintenance requirements of wind-driven generators, these power sources are not as popular especially with the continuing development of other more cost-competitive alternate power sources. Wind-driven generators are available in 400 to 3,000 W sizes with voltage outputs ranging from 12 to 240 V.

Batteries – If the current requirement for a specific cathodic protection system is relatively small, it is possible to use batteries to supply the output current. A small, isolated, well coated structure in a high resistivity environment might use a battery power supply, perhaps in conjunction with galvanic anodes, to supply the required current output. Batteries used in cathodic protection applications should be deep-cycle batteries designed for many charge/discharge cycles.

Battery manufacturers rate batteries in terms of ampere-hour capacity. Simply stated, this is the amount of current in amperes a battery can supply for a specific time interval, usually expressed in hours. Whether batteries are the primary power supply or backup for another primary power source, regular maintenance is required to ensure the batteries operate successfully over the long term. If batteries are the primary power supply, they must be replaced with new fully charged batteries on a regular schedule. Due to the maintenance and regular replacement schedule requirement, the cost associated with battery systems can be relatively high.

Closed Cycle Vapor Turbogenerator – The ORMAT® Energy Converter (OEC), a Closed Cycle Vapor Turbogenerator (CCVT), is certified for operation in Class I, Division 2 (Zone 2, Group II) conditions in onshore and offshore applications. Basically it is a self-contained power package consisting of a combustion system, a vapor generator, a turboalternator, an air-cooled condenser, a rectifier, alarms, and controls housed in a shelter. It will supply 200 to 3,000 W of filtered DC power on a continuous 24 hour-per-day basis for periods of up to 20 years with limited maintenance or repairs. Failures, however, can occur and close monitoring is thus required.

Fuel Cells – An emerging alternative energy power supply is the fuel cell and although not presently in use for cathodic protection it can possibly be a DC power source for the future. NASA originally developed this technology for the space program but only recently have commercial applications exploited the technology. A fuel cell requires three parts: an anode, a cathode, and an electrolyte. The fuel, hydrogen, passes through a porous anode catalyst, which causes the hydrogen to release its electron into the metal electrode. The hydrogen ion moves through the electrolyte where it combines with oxygen gas passing through the porous cathode and the electrons from the anode to produce heat and water.

Depending on the specific design of the fuel cell, fuel may be in many forms including gaseous hydrogen, methane, propane, and even gasoline. Air from the atmosphere usually provides the oxygen required at the cathode. The fuel cell produces current electrochemically; therefore, no moving parts are required and maintenance is minimal. Fuel cells are more efficient than any other form of energy conversion and free of polluting emissions.

2.8.4 Stray or Interference Current

Pipeline system design should seek to avoid stray currents, as they are responsible for electrolytic corrosion. This is an accelerated localized corrosion caused by stray current flow between the prevailing environment and buried pipeline. The objective of stray current analysis is to determine:

- The source of the stray current
- Where and over what area does the stray current enter the structure?
- Where and over what area does the stray current leave the structure?
- What is the magnitude of the stray current?
- How can the stray current be mitigated?

Dynamic Stray Currents are those currents that vary in amplitude and/or change in the direction of current flow. These currents can be man-made or natural in origin and can originate from any of the following sources:

- Transit systems
- Mining
- DC welding machines
- Electric power transmission

- Industrial plants (aluminum and chlorine production facilities)
- Telluric current

Dynamic stray currents can be readily detected from structure-to-electrolyte potentials and/or line current measurements.

Resolving Interference Problems – Within the same production field owned and operated by one company, appropriate electrical isolation methods are used to isolate a cathodically protected well from its flowline or a cathodically protected pipeline from a tank farm. However, when stray current is present, the method to be used to eliminate or reduce stray current interference would require an exceptional degree of cooperation between the owners and operators. Interference problems are individual in nature, and the resolution should be agreeable to all parties involved. Resolving interference problems generally involves one or more of the following:

- Removal of the detrimental effects of interfering current by installing a metallic return path
- Counteracting the effect of interfering current by applying cathodic protection
- Consultation with utility coordinating committee
- Removing or relocating the interfering current source
- Preventing the pick up or limitation of the flow of interfering current

These general approaches can be translated into some typical specific techniques:

- Adjust current output from the interfering systems
- Reduce the stray current at the source (e.g., isolation from ground, better conductivity of the negative return paths, or lower voltages)
- Apply coating to strategic area(s)
- Install a mitigation bond, or electrical connection, between the structures to drain the stray current back to its source through an electrical conductor rather than the earth

- Relocate existing structures or re-route proposed structures
- Properly locate isolating fittings
- Apply cathodic protection to the affected structure at the interfering current's discharge sit
- Relocate anodes
- Break up the structure of interest into smaller electrically isolated segments to reduce the stray current voltage gradients being traversed by the structure.

Such methods could be implemented at the design or post-design stage.

2.8.5 Environmental Control

2.8.5.1 Pipeline Cleaning

Pigging is an effective method to remove accumulated liquids and solids in a pipeline. When the pipeline is in service, operators will often pig the line to maintain line efficiency and assist in the control of corrosion by removing liquids/solids that may accumulate in the low spots of the pipeline. The periodic removal of accumulated biofilms, deposits, and liquids from pipelines will reduce the probability of MIC or under-deposit corrosion. Pigging schedules are generally based on the amount of material accumulated in the line and pushed out by each pigging event. Under certain conditions, pipelines may require chemical cleaning.

Through the different stages in the life of a pipeline, the type and frequency of pigging varies – as do the type of pigs. Pigs generally used to assist in the environmental control of internal corrosion are the conventional pigs commonly described as cleaning pigs for "on-stream" pigging. Cleaning pigs are designed to remove solids or accumulated liquids and debris in the pipeline, increasing efficiency and possibly lowering pipeline operating costs. Cleaning pigs are also used in conjunction with chemical treatment of the pipeline.

Foam pigs are manufactured from polyurethane foam. The foam is available in various densities, ranging from light to heavy. The advantages of foam pigs are that they are compressible, expandable, lightweight, and flexible.

Mandrel pigs have a metal body (steel or aluminum) and are equipped with seals (scraper cups or discs) to provide the differential pressure to propel the pig in the pipeline. One advantage of the mandrel pig is that it can be either a cleaning pig, sealing pig, or a combination of both.

Batching pigs are used to apply chemicals such as corrosion inhibitors or biocides.

Solid-cast pigs are extremely effective in removing condensate and water from wet gas systems and controlling corrosion product build-up in pipelines.

Spheres are commonly used to remove liquids from wet-gas systems, batching corrosion chemicals in pipelines, and hydrostatic testing and dewatering after pipeline rehabilitation or new construction. Spheres in general are easy to handle, will negotiate short-radius 90-degree turns, irregular turns, and bends.

Drips are designed to accumulate liquid. Certain flow-through designs preferentially accumulate water. The effectiveness of drips depends on operating parameters and location. Liquids in drips should be removed on a scheduled basis. Wide variability exists in the design of drips, and there is little consensus regarding the design and maintenance of drips.

Line-Sweeping by increasing pipeline flow velocity at river crossings and major sags on a periodic basis is sometimes used to reduce the accumulation of liquids and entrained solids. The effectiveness of line sweeping for a particular system should be evaluated by flow modeling. Take care to avoid erosion problems that could result from sweeping operations at excessive velocities.

2.8.5.2 Chemical Treatment

Chemical treatment of pipelines with corrosion inhibitors, oxygen scavengers, and biocides is perhaps the most important environmental control methodology in the oilfield. Biocides are mandatory when microbiologically induced corrosion is indicated. On the other hand, oxygen scavengers, such as uncatalyzed ammonium bisulfite (ABS), are a poor second choice relative to oxygen exclusion. Hence, oxygen exclusion must be rigorous.

In any closed loop system such as a firewater, oxygen content should not be more than ten parts per billion and an excess oxygen scavenger should always be maintained in the system. In general, the oxygen scavenger must be maintained at ten times the oxygen content in the system. Wash water and seawater treatment plants should be treated with oxygen scavengers, biocides, and corrosion inhibitors, but not at the same injection point. Biocides are generally targeted at the original source of the microbes rather than the complete system.

Corrosion inhibitors normally work in an oxygen-free environment. Therefore, corrosion inhibitors may be injected at a rate ranging from 25 ppm to 250 ppm (depending on the recent corrosion monitoring results) at a location about ten pipeline diameter-lengths from the location where the oxygen scavenger is injected. NACE Standard RP0775 defines adequate inhibition in terms of corrosion rate of 1.5 mpy for general corrosion rate and 5.0 mpy for pitting corrosion rate. The higher the recent corrosion monitoring results compared to the NACE definition, the higher the dosage rate of the inhibitor.

While scavengers and corrosion inhibitors are continuously injected, biocides may be injected monthly or twice a month at a level of about 1000 parts per million of the active ingredients. Two or more biocides should be alternated to forestall the adaptation of the microbes to the biocides. For water services, oxidizing biocides are used. These are broad-spectrum agents including chlorinated, oxygenated, and brominated products.

The non-oxidizing biocides used generally in oil-field operations are classified into metabolic (poisons) and surface-acting products. The metabolic varieties are based on gluteraldehydes, formaldehydes, quaternary phosphonium salts, isothiazoline, carbamates, metronitazole and their blends with varying compositions depending on the vendor. The surface-active agents are filming amines or surfactants. These attach to the microbe cell membrane and affect the cell's ability to regulate its internal functions.

A variety of these chemicals exist, but corrosion inhibitors are clearly the most extensive in terms of availability, usage, and technology. The use of inhibitors is the foremost method in mitigating internal corrosion of flowlines, pipelines, downhole facilities and closed circulating water systems. In operation, corrosion inhibitors decrease the deterioration rate of pipeline material due to reaction with its environment either by anodic polarization, cathodic polarization, or by increasing the electrical resistance of the corrosion circuit. A qualitative classification of corrosion inhibitors is illustrated in Figure 2.30.

There are two broad classes of inhibitors: inorganic inhibitors (water-soluble) and organic inhibitors (oil soluble). Generally, inorganic inhibitors are used for cooling water towers, heating and cooling media, dehydration glycol, and sweetening system amine solutions. The organic inhibitors are used in oil, gas, and water wells, oil and gas flowlines, gas systems and water systems.

The choice of whether to use a water-soluble or oil-soluble corrosion inhibitor depends on the percentage of free water as well as the fluid flow velocity. A pipeline containing higher than a 50% water cut normally gets a water-soluble inhibitor. Pipelines carrying oilfield fluid with less than 50% water use the hydrocarbon-soluble inhibitor unless the fluid flow rate is less than 7 feet per second. Low velocity pipelines are characterized by stratified flows in which water, suspended particles plus fine particulates flow along the 6 o'clock portion of the pipeline while oil and other hydrocarbon fluids flow on top. If the flow rate is quite low, the fine particulates might settle, trap water and foster the growth and development of microorganisms. In that event, both corrosion inhibitors and biocides would be needed.

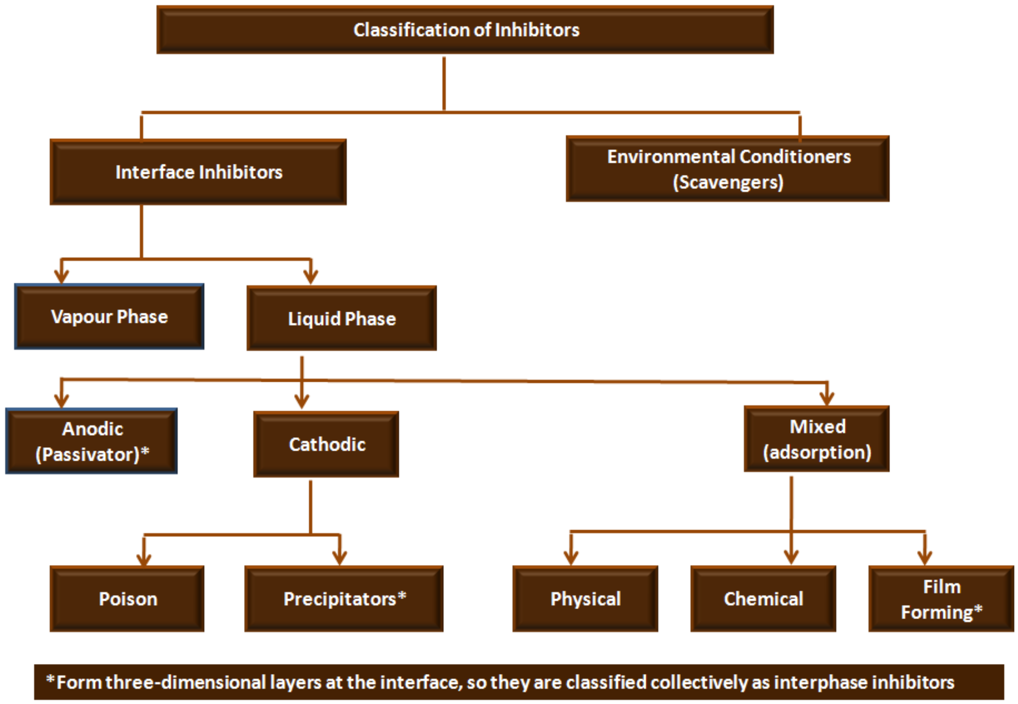


Figure 2.30 Classification of Inhibitors

As the name implies, scavengers are used to remove aggressive substances such as oxygen from oilfield fluids. The most commonly used chemical scavengers in the oil field are sodium sulfites (fresh water), sodium bisulfites (seawater), ammonium bisulfites (seawater), and sulfur dioxides (fresh water, brine).

Interface inhibitors can be in liquid or vapor phase. They form corrosion inhibiting film on the metal surface. Liquid phase inhibitors are further classified based on whether they inhibits anodic reactions, cathodic reactions or both anodic/cathodic electrochemical reactions.

Inorganic anodic inhibitors are generally interface inhibitors; they form a film that inhibits the anodic reaction. If they are oxidizing anions such as nitrates, nitrites and chromates, they are only able to passivate steel in the absence of oxygen. The non-oxidizing ions such as phosphate, tungstate, and molybdate, require the presence of oxygen to passivate carbon steel. Oxidizing or non-oxidizing, these inhibitors protect the steel surface by a passivating combination of adsorption and oxide formation, which inhibits the anodic metal loss. Chromates are known to form not only ferric oxides but also chromate oxide on the carbon steel as long as sufficient chromate remains.

Passivating inhibitors are generally the most effective of all inhibitors because of their ability to starve the corrosion reaction process. However, at insufficient concentration and depending on the type and the ionic concentration of the aggressive medium, these inorganic passivating inhibitors could accelerate the corrosion process. This is why these inhibitors are also known as "dangerous" inhibitors.

With the passivating film in place, the steel surface is cathodic. However, if the film is penetrated by a scratch and the film is unable to repair itself due to insufficient concentration of the oxidizing inhibitor, a small anodic region will form as a result of the scratch. The small-anode large-cathode scenario will result in accelerated pitting corrosion of the steel surface. A non-oxidizing passivator, at an insufficient concentration, would result in too much oxygen and would depolarize the cathodic steel surface creating of an anodic region similar to those created by oxidizing inhibitors.

Aside from the effect of an insufficient concentration, the presence of easily oxidizable compounds such as hydrogen sulfide is deleterious to the passivating ability of oxidizing inhibitors such as chromates. The chromates would preferentially oxidize hydrogen sulfide which would result in an insufficient concentration of the chromate to passivate the steel surface. A high concentration of chloride ions is also deleterious to the passivating ability of chromate. This is because the chloride ions preferentially adsorb on the steel surface and prevent the passivating inhibitors from polarizing the steel surface.

Inorganic cathodic inhibitors, such as calcium, magnesium and zinc salts, are used to decrease the corrosion reaction rate on the metal surface by poisoning the reaction. In brines, these inorganic cathodic salts shield the metal surface from corrosion by reacting with dissolved salts or gases; they then precipitate insoluble compounds onto the metal surface. Such insoluble compounds also prevent the egress of oxygen to the metallic surface, thus minimizing the cathodic reaction rate.

In an acidic medium, an inorganic cathodic inhibitor, acting as corrosion reaction poison, could inhibit the hydrogen atom recombination and allow the egress of molecular hydrogen into the metal. This could in turn result in hydrogen blisters and hydrogen-induced cracking.

Organic corrosion inhibitors are generally classified as mixed inhibitors. Polar, oleophilic molecules such as benzotriazole, inhibit corrosion by forming a protective film either by chemical adsorption or electrostatic adsorption. They are particularly effective in oil systems and produced water systems with traces of oil, because the metal pipe surface is wetted by oil. Because of its oleophilic nature, inhibitor systems in oil and gas wells have a high film persistency and retreatment is infrequent. Nonetheless, the inhibitor film is not permanent, and sufficient concentrations must be present for it to repair itself.

The majority of corrosion inhibitors used in pipelines are organic and are usually introduced by either continuous treatment or batch treatment. Contained in drums, the inhibitor consists of three parts (1) a solvent carrier, (2) additives to stabilize the mixture and prevent emulsion formation, and (3) an inhibitor base. The active ingredient is the inhibitor base that consists primarily of organic amines or amine salts, such as diamines, quaternary ammonium chlorides, poly (amido-amines) and imidazolines. Inhibitors work well in areas where the required concentration of the active ingredient can be readily maintained. The key desirable inhibitor properties include:

- Solubility or dispersability in its carrier solvent, additives and the oilfield fluids of interest
- Compatible with downstream processes
- Compatible with other chemicals
- Mobility of individual components
- Thermal stability
- Partitioning properties between oil and water
- Emulsification properties
- Viscosity or pour point

- Corrosivity
- Foaming properties
- Freeze-thaw characteristics
- Environmental friendliness

Inhibitor selection is essentially a four step process. The physical layout, the fluid to be inhibited, and the mechanical system of the location must first be reviewed. The inhibitor application method and delivery system must be reviewed to ensure that the chemical gets to the intended location at the intended time. The key desirable inhibitor properties must be determined and documented. A few inhibitors should be selected based on the prevailing experience and the desired attributes already identified in the first three steps.

A third-party laboratory screening test should be conducted based on simulated conditions that are hydrodynamically representative of the anticipated field environment. This should be an unbiased investigation of the feasibility of a few candidate inhibitors, using an appropriate test protocol. Key testing protocol includes:

- Inhibitor thermal stability testing to ensure the fluid will pump at all times
- Foaming tests to ensure that the corrosion inhibitor product does not foam or emulsify
- Low pressure, dynamically agitated electrochemical screening tests
- High pressure, high temperature static or dynamic testing

There are two basic types of standard laboratory testing: gravimetric and electrochemical. These are used to understand of the effects of the various candidate chemical inhibitors by varying the relevant environmental parameters. However, it is the more complex laboratory testing protocols that can more accurately simulate actual field environments. These are:

- Rotating autoclave wheel testing (Wheel Testing)
- Rotating cylinder electrode (RCE) testing
- Rotating cylinder autoclave testing

- Stagnant or stirred autoclave testing
- Recirculating flow loop testing
- Autoclave flow loop testing
- Jet-impingement testing

To assess how the inhibitors perform in the specific oilfield environment, a field trial of the final two selected inhibitors should be conducted to select the most appropriate inhibitor for the desired application. For this test, a side stream bypass loop may be used to provide the advantage of an in-service inhibitor test with the actual product streams. This could be a branched section of the pipeline or a side stream from a piece of equipment, a complete flow-loop, or a pilot plant that duplicates the equipment of interest on a smaller scale. This stream should pass through many test stations to simultaneously test a variety of materials. The bypass also simulates different flow regimes, hydrodynamics, water cuts, corrosion variables, inhibitor delivery methods, etc. In all cases, the diverted portion of the mainstream is not returned to the original stream and the effluent from the bypass loop is discarded.

Corrosion inhibitors have application in the following services. The inhibitor application methods are also different for specific services.

- Producing wells
    - With packered annuli
        - Formation squeeze application method
        - Tubing displacement method
        - Nitrogen squeeze or nitrogen displacement method
        - Partial tubing displacement and yo-yo treatment method
        - Hydraulic pump well treatment method
    - With open annuli
        - Annular batch application method
        - Continuous application
- Surface facilities

- Production and plant facilities
- Flow lines and gathering lines
- Tanks and vessels
- Gas handling systems and gas plants
- Amine sweetening systems
- Pipelines
- Gas coolers
- Cooling and heating systems

- Water injection systems (air-free application is essential)
- Disposal water systems
- Brackish water systems for fire-fighting systems
- Well acidizing service (acid inhibitors)
- Volatile corrosion inhibitor service

Generally, internal corrosion of pipelines is controlled by a combination of chemical injection and physical cleaning (pigging). The cleaning pigs are used to periodically clear debris and foreign matter that could be the unwanted catalyst for internal corrosion. For overall effectiveness of corrosion control activities, chemical treatment programs should include corrosion monitoring.

2.8.6 Corrosion Remediation Methods

A remediation method is a corrective action taken to mitigate deficiencies in the corrosion protection system. This could include relocation, replacement, rehabilitation, and repair. The rest of this section will therefore be devoted to the discussion of actions taken to remedy the corrosion protection system after corrosion has been discovered by inspection techniques including ILI, ECDA, ICDA, and SCCDA.

2.8.6.1 External Corrosion Affected Pipelines

If coating defects, disbondment, serious holidays or other anomalies of the external coating are found at an excavated location, all the existing pipeline coating must be removed, the steel abrasively blasted, and the pipeline recoated to minimize the current requirements for cathodic protection.

Appropriate repair methods should be implemented for all the external-corrosion-affected pipe seam, girth weld, pipe body, and bend based on the five most common repair strategies that appear in Table 2.13.

The newest polymer-based pipeline repair technology is the composite reinforcements or the "composite wrap" (Figure 2.31) which are used to restore the structural integrity of a pipeline with degradation due to corrosion or damage, such as:

- External corrosion, which may or may not cause leaking
- External damage such as dents, gouges, fretting (at supports)
- Internal corrosion, which may or may not cause leaking

Composite material systems that are currently available fall into two generic groups: prepacked (Type A) and specially designed composite repair systems (Type B). Type A represents those material systems that are supplied in a prepacked form and are often held as a stock item to be applied by maintenance personnel at the facility. Type B represents the situation in which the repair is specified and designed on an on-demand basis. Currently, specialty contractors usually apply these systems.

The production of a composite laminate system requires the combination of a network of fibrous reinforcement and a thermosetting polymer matrix that undergoes a chemical curing process. This often involves the use of a liquid resin and layers of reinforcing material at the point of application. This means that the load carrying material is formed as the repair is carried out. The final properties of the material are significantly influenced by the method of application, the details of the lay-up and the form of reinforcement used. The differences in the final properties are due to variations in the fiber fraction of the composite, fiber orientation in the applied loading, and the final cure state. A typical composite wrap appears in Figure 2.31.

Figure 2.31 Composite Wrap

If needed, damaged pipe joints should be replaced. Reduction of pressure should be considered to better control crack initiation and growth.

2.8.6.2 Internal Corrosion Affected Pipelines

The general discussion on internal corrosion control under the section entitled "Overview of Corrosion Control Methods" is relevant here. In particular, intelligent/scraper pigging plus chemical treatments with inhibitors, biocides, and/or oxygen scavengers should be carried out to alter the internal pipeline environment. The appropriate repair methods should be implemented for all the internal-corrosion-affected pipe seam, girth weld, pipe body, and bend, based on the recommendations shown in Table 2.13. As in the case of SCC, reduction of pressure should be considered to better control crack initiation and growth.

2.8.6.3 SCC-Affected Pipelines

Whenever SCC is discovered, all existing pipeline coatings must be removed with the surface grit blasted to a white (NACE No. 1/ SSPC-SP 5) or near white (NACE No. 2/SSPC-SP 10) surface finish. This imparts sufficient compressive residual stress in the pipe surface to neutralize the residual tensile stress that is a causative factor for SCC. The pipeline should be recoated with one of the following coating systems:

- Fusion bonded epoxy
- Liquid epoxy
- Urethane

These coatings can effectively prevent SCC due to the following three factors:

- The resistance of the coating to disbondment
- The ability to pass CP current should the coating fail
- The type of surface preparation used for the coating

The SCC affected areas must be repaired either by cut-outs and replacement, or by grinding with or without a full-encirclement reinforcing sleeve based on the five most common repair strategies in Table 2.13. If necessary, the SCC affected pipe joints should be replaced. Reduction of pressure should be considered to better control crack initiation and growth. Even then, the line should be hydrostatically re-tested to ensure that it is safe to operate at the lower pressure.

Table 2.13: Repair Strategies for External Corrosion, Internal Corrosion and SCC

		PRIMARY REPAIR STRATEGIES[1]				
Anomalies		Weld Metal Deposition[2]	Type A Sleeve	Type B Sleeve	Composite Reinforcement	Hot Tap
External Metal Loss ≤80% w.t.	Pipe Seam	Yes	Yes	Yes	Yes	No
	Girth Weld	Yes	Yes	Yes	Yes	No
	Pipe Body	Yes	Yes	Yes	Yes	Yes
	Bend	Yes	Yes[3]	Yes[3]	Yes[4]	Yes
Internal Metal Loss ≤80% w.t.	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	Yes
	Bend	No	No[3]	Yes[3]	No	Yes
External Metal Loss >80% w.t.	Pipe Seam	Yes	No[8]	Yes	No[8]	No
	Girth Weld	Yes	No[8]	Yes	No[8]	No
	Pipe Body	Yes	No[8]	Yes	No[8]	Yes
	Bend	Yes	No[8]	Yes[3]	No[8]	Yes
Internal Metal Loss >80% w.t.	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	Yes
	Bend	No	No[3]	Yes[3]	No	Yes

		Weld Metal Deposition[2]	Type A Sleeve	Type B Sleeve	Composite Reinforcement	Hot Tap
Leaks, Cracks, Arc Burns and Girth Weld Flaws [12]	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	No[10]
	Bend	No	No	Yes[3]	No	No[10]
	Thread Collar	No	No	Not Practical	No	No
Dents with Stress Concentrators	Pipe Seam	No	Yes [5,6]	Yes[6]	No	No
	Girth Weld	No	Yes [5,6]	Yes[6]	No	No
	Pipe Body	No	Yes [5,6]	Yes[6]	No	Yes[11]
	Bend	No	Yes[3, 5,6]	Yes[3,6]	No	Yes[11]
Plain Dents	Pipe Seam	No	Yes[5]	Yes	No[7]	No
	Girth Weld	No	Yes[5]	Yes	No[7]	No
	Pipe Body	No	Yes[5]	Yes	No[7]	Yes[11]
	Bend	No	Yes[3,5]	Yes[3]	No	Yes[11]

1. Pipe replacement is always an effective repair
2. Use of weld deposition requires a minimum pipe wall thickness and control of welding parameters to prevent burn thru. This generally prevents use of this technique in pipes with external metal loss > 80% wall thickness except in heavy wall pipelines. At this time we do not recommend use of this technique for wall <0.181".
3. Metallic sleeves both bolted and weld-on are available for bends and fittings.
4. Special techniques utilizing multiple overlapping sleeves are required for bends.
5. A hardenable incompressible filler shall be used to fill the annular space between the dent and the sleeve.

6. Mechanical damage in a dent must be removed by grinding prior to installation of the sleeve
7. Only certain types of composite repairs when used with an incompressible filler are adequate for the repair of dents and such repairs must show by reliable engineering tests and analysis to permanently restore the serviceability of the line pipe.
8. Conservative industry practice is to limit the use of Type A and composite sleeves to external metal loss ≤ 80% of nominal wall. For the case of external metal loss > 80%, a minimum wall must be present for Type A sleeves and composite reinforcement repair techniques. At this time we recommend a minimum wall of 50 mils, precise non-destructive testing of pit depth, no internal corrosion and sound engineering practice.
9. Other repair methods may be used provided they are based on sound engineering practice
10. Cracks that are not leaking can be hot tapped to remove the crack.
11. If entire dent can be removed
12. Arc burns and girth-weld flaws can be repaired by grinding out the defect and/or Type A or B sleeves as long as the repairs are based on sound engineering practice.

Chapter 3: Regulations

After completing this chapter, students should:

- Be familiar with timeline in which pipeline regulations came into existence.
- Be able to recognize the United States government agencies that are associated with pipeline operations.
- Know which regulations apply to the different types of pipeline products (i.e. natural gas and hazardous liquid).
- Know where to find frequently asked questions and regulatory interpretations for natural gas and hazardous liquid systems.

3.1 Overview of 49 CFR and Integrity Requirements

The Code of Federal Regulations (CFR) is the codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government. It is divided into 50 titles that represent broad areas subject to Federal regulation. Each volume of the CFR is updated once each calendar year and is issued on a quarterly basis[1]. Each title is divided into chapters, and each chapter is further divided into parts that cover specific regulatory areas. Title 49, Chapter I, contains several parts related to pipeline operations:

- Part 190, Pipeline Safety Programs and Rulemaking Procedures
- Part 191, Transportation of Natural and Other Gas by Pipeline; Annual reports, Incident Reports, and Safety Related Condition Reports
- Part 192, Transportation of Natural and Other Gas by Pipeline; Minimum Federal Safety Standards
- Part 193, Liquefied Natural Gas Facilities; Federal Safety Standards
- Part 194, Response Plans for Onshore Oil Pipelines
- Part 195, Transportation of Hazardous Liquids by Pipeline

History of Regulations

The following represents a timeline and illustrates the development of existing natural gas and hazardous liquids pipeline regulations:

- August, 1968, Pipeline Safety Act (Based on ASME B31.8)
- 1969, NACE SP0169, "External Corrosion Control for Underground and Submerged Piping Systems"
- August, 1971, 49 CFR 192 for Natural Gas
- August, 1975, 49 CFR 195 for Hazardous Liquids
- May, 2001, HCA, Integrity Management Rule for Liquids >500 miles
- January, 2002, ASME B31.8S, "Managing System Integrity of Gas Pipelines"
- February, 2002, Integrity Management Rule for Liquids <500 miles
- February, 2002, NACE Standard for In-Line Inspection
- October, 2002, Operator Qualification Rule takes effect
- November, 2002, NACE Standard for ECDA
- December, 2002, Pipeline Safety Improvement Act
- September, 2002, OPS Request for Security Plans
- January, 2004, Integrity Management Rule for Gas

The pipeline safety and integrity regulations are based upon industry standards. Some organizations that participate in pipeline integrity standards and rule-making activities are:

- A.S.M.E. – American Society of Mechanical Engineers
- A.PI – American Petroleum Institute
- A.GA. – American Gas Association
- I.N.G.A.A – Interstate Natural Gas Association of America
- NACE – NACE International
- PRCI – Pipeline Research Council, International

- I.SO – International Standards Organization.

Associated Government Agencies

The Office of Pipeline Safety (OPS) oversees federal pipeline safety regulations[2] with the following mandate:

- Assure safety in design, construction, inspection, testing, operation, and maintenance of natural gas and hazardous liquid pipeline facilities and in the construction, operations, and maintenance of LNG facilities
- Set out parameters for administering the pipeline safety program
- Require pipeline operators to implement and maintain anti-drug and alcohol misuse prevention programs for employees who perform safety-sensitive functions
- Delineate requirements for onshore oil pipeline response plans

According to the Department of Transportation (DOT), the fundamental objectives of the regulations are to[3]:

- provide safety for workers and the public
- protect property and the environment
- minimize cost to the public, industry, and government
- minimize economic and social disruption
- provide uniform regulations that support consistent hazard classification and packaging standards and clear hazard communication
- provide regulations in harmony with world-wide regulatory systems which facilitate and reduce the cost of foreign trade

In 2004, under the Norman Y. Mineta Research and Special Programs Improvement Act, the DOT formed a group specializing in Pipeline and Hazardous Materials Safety, PHMSA. The purpose of the act was to provide the Department a more focused research organization and establish a separate operating administration for pipeline safety and hazardous materials transportation safety operations.[4]

Along with the DOT, there are numerous government agencies that regulate pipeline operations. (Figure 3.1)

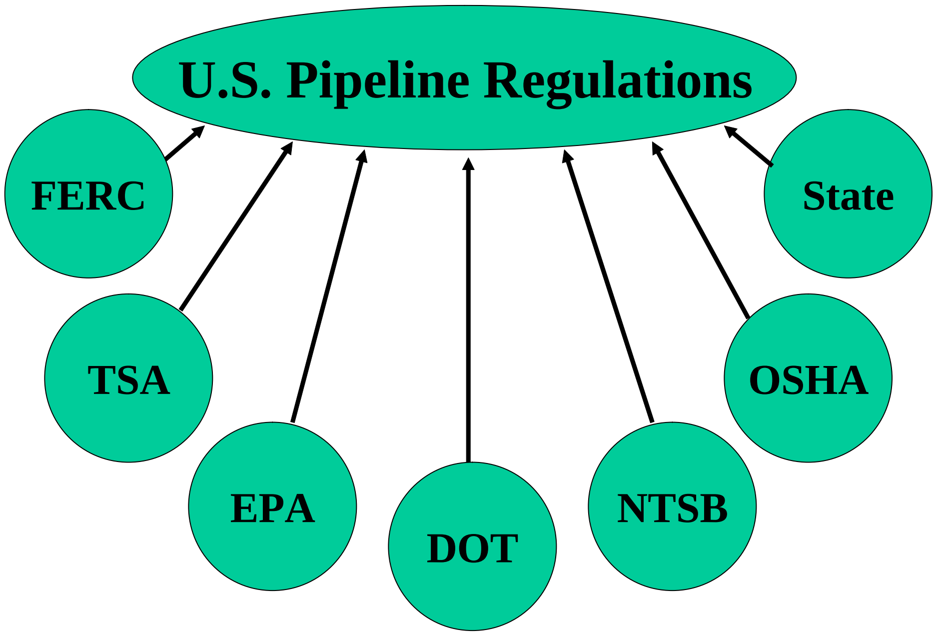


Figure 3.1 Government Agencies Associated with Pipeline Operations

The Federal Energy Regulatory Commission (FERC) regulates and administers energy rates and tariffs, and other economic aspects of the energy industry. FERC regulations and policies promote secure, high quality, environmentally responsible pipeline systems.

The Transportation Security Administration (TSA) is responsible for protecting transportation systems to ensure freedom of movement for people and commerce. TSA implements regulations and develops processes and technologies that protect transportation systems. TSA is also responsible for pipeline security.

The Environmental Protection Agency (EPA) is responsible for implementing and enforcing environmental protection regulations. This includes regulations that affect pipeline operators in the areas of spill prevention and control, air emissions and hazardous waste disposal.

The Department of Transportation (DOT) develops, issues, and enforces regulations for transportation operators in the United

States. As part of DOT, the Pipeline Hazardous Materials Safety Administration (PHMSA) has public responsibilities for safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines. PHMSA provides research and technology funding for DOT and private industries, and is responsible for pipeline safety regulations, including integrity management. As part of PHMSA, the mission of the Office of Pipeline Safety is to ensure the safe, reliable and environmentally sound operation of the nation's pipeline transportation system. OPS is responsible for enforcement of pipeline safety regulations and they conduct compliance audits of pipeline operations and issues citations for non-compliance.

The National Transportation Safety Board (NTSB) primarily investigates and determines failure causes and issues corrective action recommendations for transportation incidents including air, railroad, shipping, highway and pipeline. In addition NTSB issues corrective action recommendations to other federal regulatory agencies such as the DOT.

The Occupational Safety and Health Administration (OSHA) implements and enforces workplace safety and health regulations for U.S. workers. OSHA establishes regulations and enforces standards, provides training and encourages continuous improvement in pipeline construction, operation, and maintenance. OSHA also administers the "whistle blower" provision of the Pipeline Safety Improvement Act that protects workers from retaliation by their employers from reporting unsafe or non-compliant pipeline operations. All of the above are U.S. federal agencies. There are also state laws, some of which have more stringent pipeline integrity requirements. Some of the states are also enforcement agents for DOT.

3.1.1 Hazardous Liquid 49 CFR Part 195

Hazardous Liquid 49 Code of Federal Regulations (49 CFR) Part 195 prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide. The initial integrity management rule for hazardous liquid pipelines, which applied to operators with more than 500 miles of pipeline, became effective May 29, 2001. A rule change effective February 15, 2002, made the rule applicable to owners of all hazardous liquid pipelines, regardless of length. Table 3.1 beginning on page 6 displays a timeline of Compliance Dates and Milestones for the Hazardous Liquid rule.

The pipeline integrity management rule for Part 195 is located in Part F of 49 CFR, Section 195.452. This rule applies to each hazardous liquid and carbon dioxide pipeline that could affect a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

Table 3.1: The Effective Compliance Dates and Requirements of Title 49 CFR Part 195 Subpart F for Hazardous Liquid Pipeline Systems

Effective Date	Compliance Requirement
5/29/2001	Initial Rule, applies to Hazardous Liquid Pipelines greater than 500 miles (need not be contiguous)
2/15/2002	Initial Rule, applies to Hazardous Liquid Pipelines less than 500 miles
12/31/2001	Identify segments that could affect HCAs for Pipelines greater than 500 miles
3/31/2002	Prepare Baseline Assessment Plan and Framework for Pipelines greater than 500 miles
11/18/2002	Identify segments that could affect HCAs for Pipelines less than 500 miles
2/18/2003	Prepare Baseline Assessment Plan and Framework for Pipelines less than 500 miles
9/30/2004	Assess at least 50% of Pipeline affecting HCAs for Pipelines greater than 500 miles
8/16/2005	Assess at least 50% of Pipeline affecting HCAs for Pipelines less than 500 miles
3/31/2008	Pipelines subjected to initial rule must complete assessment of all BAPs for pipelines greater than 500 miles

Table 3.1: (Continued)The Effective Compliance Dates and Requirements of Title 49 CFR Part 195 Subpart F for Hazardous Liquid Pipeline Systems

Effective Date	Compliance Requirement
2/17/2009	Pipelines subjected to initial rule must complete assessment of all BAPs for pipelines less than 500 miles

3.1.1.1 Definitions

Part 195 contains certain definitions that are useful in order to properly understand the regulations. The terms in Table 3.2 beginning on page 7 are critical to Part 195:[8]

Table 3.2: Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Abandoned	permanently removed from service
Administrator	the Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation
Barrel	a unit of measurement equal to 42 U.S. standard gallons
Breakout Tank	a tank used to • relieve surges in a hazardous liquid pipeline system, or • receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline
Carbon dioxide	a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state

Table 3.2: (Continued) Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Computation Pipeline Monitoring (CPM)	a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release
Corrosive product	"corrosive material" as defined by Sec. 173.136 Class 8-Definitions of this chapter
Exposed Pipe	a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water
Flammable product	"flammable liquid" as defined by Sec. 173.120 Class 3-Definitions of this chapter
Gathering line	a pipeline of 219.1mm or less nominal outside diameter that transports petroleum from a production facility.
Gulf of Mexico and its inlets	the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters) deep, as measured from the mean low water
Hazard to navigation	for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water
Hazardous liquid	petroleum, petroleum products, or anhydrous ammonia.

Table 3.2: (Continued) Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Highly volatile liquid or **HVL**	a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8^{o} C (100^{o} F).
In-plant piping system	piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under Sec. 195.406(b)
Interstate pipeline	a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.
Intrastate pipeline	a pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.
Line section	a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and block valve, or between adjacent block valves
Low-stress piping	a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.
Nominal wall thickness	the wall thickness listed in the pipe specifications

Table 3.2: (Continued) Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Offshore	beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.
Operator	a person who owns or operates pipeline facilities
Outer Continental Shelf	all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.
Person	an individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof
Petroleum	crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas
Petroleum product	flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds
Pipeline or line *pipe*	a tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another

Table 3.2: (Continued) Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Pipeline or pipeline system	all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks
Pipeline Facility	new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide
Production facility	piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where CO_2 is produced, and preparing it for transportation by pipeline. This includes piping between piping treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)
Rural area	outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development

Table 3.2: (Continued) Part 195 Terms and Definition(s)

Term(s)	Definition(s)
Specified minimum yield strength	the minimum yield strength, expressed in psig (kPa), prescribed by the specification under which the material is purchased from the manufacturer
Stress level	the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength
Surge pressure	pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream
Toxic product	"poisonous material" as defined by Sec. 173.132 Class 6, Division 6.1-Definitions of this chapter
Unusually Sensitive Area (USA)	a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under Sec. 195.6

3.1.1.2 Category Definition

Pipelines are split into three categories (Category 1, Category 2, and Category 3) that define when the pipeline should be analyzed. Category 1 pipelines are those pipelines existing on or before May 29, 2001 that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline that are subject to this part. Category 2 pipelines are those pipelines existing on or before May 29, 2001 that were owned or operated by an operator who owned or operated less than 500 miles of pipeline that are subject to this part. Category 3 pipeline segments are those segments constructed or converted after May 29, 2001.

This portion of the regulations uses the category designations to define the dates in which the integrity management programs have to be written. The integrity management program should address the risks no later than the time frame specified in the integrity management program. Category 1 Pipelines should have had a written integrity management program no later than March 31, 2002. Category 2 Pipelines should have had a written integrity management program no later than February 18, 2003. All Category 3 Pipelines should have a written integrity management program no later than one year after the date the pipeline begins operation.

3.1.2 Integrity Management Process

The written integrity management program must include a plan to carry out baseline assessments (or risk plan) of line pipe. This Baseline Assessment Plan must identify the specific integrity assessment method(s) for each segment that can affect an HCA. These methods must be based on the identification of the most significant integrity threats for the specific segment. The plan must also include a schedule indicating when the assessments of each segment will be performed. The schedule must be risk-based, meaning that higher-risk segments are scheduled before lower-risk segments. Operators must document the technical basis for the assessment methods they select and the risk analysis performed to establish the schedule.

Once baseline assessments are completed, operators must conduct periodic assessments on identified pipeline segments. The frequency of reassessment depends on the risk presented by each segment. Risk is determined based on many factors, including the pipe condition as learned from the integrity assessment; leak history; pipeline design features; operating and maintenance practices; and factors outside the pipeline such as population density or the presence of drinking water sources. The regulations provide time limits within which these future assessments must be performed.[5] The Integrity Management Process Based on API 1160 appears as Figure 3.2.

Key features of the Hazardous Liquids Regulation include HCA enhanced protection. HCAs include Unusually Sensitive Areas, urbanized areas and other populated places, as well as commercially-navigable waterways. All baseline assessments for pipelines subject to the initial rule must be completed by March 31, 2008. At least half of the line affecting HCAs must be assessed by

September 30, 2004. The corresponding dates for pipeline added by the revised rule (called category 2) are February 17, 2009 and August 16, 2005, respectively. An operator may use an assessment conducted prior to the effective date of the rule (after January 1, 2005, for category 1 pipelines and after December 18, 1996, for category 2 pipelines) to satisfy the baseline assessment requirement.

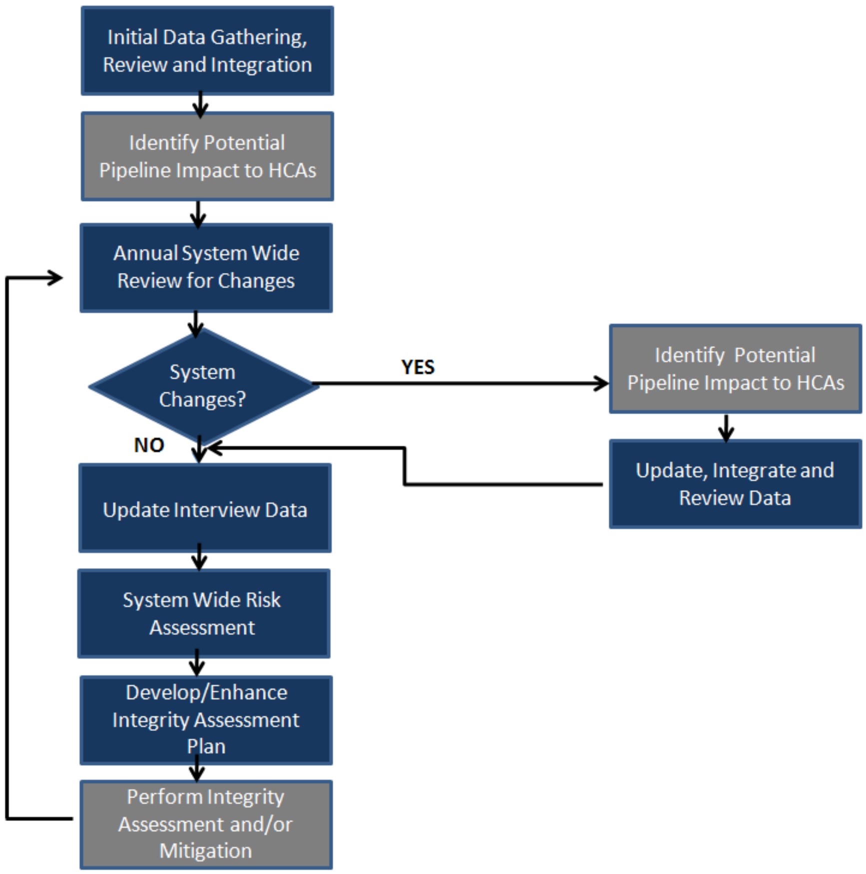


Figure 3.2 Integrity Management Process Based on API 1160[6]

3.1.2.1 Protocols

There are protocols necessary in order to carry out pipeline integrity for hazardous liquid systems. These protocols reflect the December 2004, protocol revisions. The protocols are as follows:

- HCA identification
- Baseline assessment plan
- Integrity assessment results review

- Remedial action
- Risk analysis
- Preventive and mitigative measures
- Continual process of evaluation and assessment
- Program evaluation

3.1.2.2 Pipeline Assessments and Inspection

In 2004, the number of pipeline segment miles inspected due to the liquid integrity management requirements was approximately 95,000 miles. This mileage includes both the miles inspected in pipeline segments that affect HCAs as well as the miles inspected coincident with the HCA inspections required by the Liquid IM rule. Also in 2004, there were more than 11,000 anomalies repaired or mitigated, both within pipeline segments that could affect HCAs and in pipe segments that could not and were not required to be addressed by the Liquid IM Rule.

There are several methods that can be used to assess the integrity of a Hazardous Liquids Pipeline. The most common methods used to assess the integrity of a liquid pipeline is by an internal inspection tool (or tools capable of detecting corrosion and deformation anomalies including dents, gauges, and grooves), a hydrostatic test (or pressure test), or another technology that the operator can prove provides an equivalent understanding of the condition of the line pipe. Any operator who chooses another technology must first contact OPS 90 days before conducting the assessment by sending a notice to the OPS.

After completing the Baseline Assessment Program (BAP), an operator is to continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipe segment that could affect a High Consequence Area. It is up to the operator to establish intervals (no more than five years) to continue to assess the line pipe's integrity. If an operator chooses an assessment schedule that exceeds five years, the operator must justify this schedule by reliable engineering evaluation combined with another technology such as an external monitoring technology to provide an understanding of the condition of the line pipe equivalent to that which can be obtained from the usual assessment methods noted above. The operator must provide OPS with their justification for a longer interval and propose an alternative interval 270 days before the end of the five years (or less) interval.

An operator may want a longer assessment time interval to use a sophisticated internal inspection technology that is not available at this time, but will become available in the proposed timeframe. If this is the case, the operator needs to justify this to the OPS and follow the requirements mentioned in the paragraph.

3.1.3 Natural Gas 49 CFR Part 192

The United States has a well established program of technical standards and regulatory oversight of oil and natural gas operations. In 1968, the Natural Gas Pipeline Safety Act was passed. It is based on a technical standard developed by the American Society of Mechanical Engineers (ASME) B31.8. Table 3.3 beginning on page 17 displays a timeline of Effective Compliance Dates and Requirements of Title 49 CFR Part 192 Subpart O Hazardous Gas Rule.

Operators were required to complete the baseline assessment of 50% of their covered segments, beginning with the highest risk segment, by December 17, 2007 and must complete 100% of their covered segments by December 17, 2012. Direct Assessment may be used for external corrosion, internal corrosion, and stress corrosion cracking. Certain defects must be remediated within specific time limits. For immediate conditions, a pressure reduction must be implemented until the condition is repaired. Operators must conduct risk assessments to identify additional preventive and mitigative measures to protect high consequence areas and enhance public safety.

An operator’s integrity management program must include methods to measure the effectiveness of their program. At a minimum, it must include the performance measures specified in ASME/ANSI B31.8S, and submit a semi-annual report of performance measures to OPS.

Table 3.3: The Effective Compliance Dates and Requirements of Title 49 CFR Part 192 Subpart O for Hazardous Gas Pipeline Systems

Effective Date	Compliance Requirement
December 17, 1998	an operator may consider manufacturing and construction related defects to be stable if the operating conditions on the covered segment have not significantly changed since this date
December 17, 2002	an operator may use a prior integrity assessment conducted before this date as a baseline assessment if the integrity assessment meets the baseline requirements and subsequent remedial actions have been carried out
December 15, 2003	final rule issued
February 14, 2004	final rule takes effect
April 6, 2004	corrections to the final rule take effect
May 26, 2004	corrections to the final rule take effect
June 17, 2004	Pipeline safety statute requires operators to have begun baseline integrity assessments of covered segments
August 31, 2004	deadline for first time reporting of semi-annual performance measures to OPS/ state regulators
December 17, 2004	an operator must have developed a written integrity management program (framework) that contains all the elements described in §192.911 and addresses the risks on each covered transmission pipeline segment
December 17, 2004	an operator must have completed the identification of high consequence areas

Table 3.3: (Continued) The Effective Compliance Dates and Requirements of Title 49 CFR Part 192 Subpart O for Hazardous Gas Pipeline Systems

Effective Date	Compliance Requirement
December 17, 2006	last date for identifying a high consequence area based on a prorated number of buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline

3.1.3.1 Definitions

Part 192 contains certain definitions that are useful to know in order to properly understand the regulations. The terms in Table 3.4 beginning on page 18 are critical to part 192.7:

Table 3.4: Part 192 Term(s) and Definition(s)

Term(s)	Definition(s)
Assessment	the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment
Confirmatory direct assessment	an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment
Covered segment or covered pipeline segment	a segment of gas transmission pipeline located in a high consequence area; the terms gas and transmission line are defined in §192.3
Direct assessment	an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity; the process includes the gathering and integrating risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation

Table 3.4: (Continued) Part 192 Term(s) and Definition(s)

Term(s)	Definition(s)
High consequence area	an area established by one of the methods described in paragraphs (1) or (2) below: 1. An area defined as: I. A Class 3 location under §192.5; or II. A Class 4 location under §192.5; or III. Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or IV. Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site. 2. The area within a potential impact circle containing: I. 20 or more buildings intended for human occupancy, or II. An identified site

Table 3.4: (Continued) Part 192 Term(s) and Definition(s)

Term(s)	Definition(s)
Identified site	(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days (the days need not be consecutive) in any twelve (12) month period. Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks (the days and weeks need not be consecutive) in any twelve (12) month period. Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities
Potential impact circle	a circle of radius equal to the potential impact radius (PIR)

Table 3.4: (Continued) Part 192 Term(s) and Definition(s)

Term(s)	Definition(s)
Potential impact radius (PIR)	the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property PIR is determined by the formula r = 0.69* (square root of (p*d 2)), where ‘r’ is the radius of a circular area in feet surrounding the point of failure, ‘p’ is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and ‘d’ is the nominal diameter of the pipeline in inches. **Note**: 0.69 is the factor for natural gas: this number will vary for other gases depending upon their heat of combustion; an operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S–2001 (Supplement to ASME B31.8; incorporated by reference, see §192.7) to calculate the impact radius formula
Remediation	a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event

In order to implement this subpart, an operator must follow this subpart and ASME/ANSI B31.8S and its appendices.

3.1.3.2 Protocols

The Gas Integrity Management rule applies to gas transmission operators who fall under the jurisdiction of 49 CFR Part 192. The rule became effective February 14, 2004. Key features of this regulation include enhanced protection for defined High Consequence Areas (HCAs). HCAs can be identified using the class location method, or the potential impact radius method. The Natural Gas Integrity Assessment requires following a list of protocols. These protocols are used to implement gas integrity management. The protocols are as follows:

- Identify HCAs in accordance with 192.905

- Baseline Assessment Plan that meets requirements of 192.919 and 192.921
- Identify Threats, Data Integration, and Risk Assessment per 192.917 and 192.935
- DA Plan that meets the requirements of 192.923, and depending on the threat assessed, of 192.925, 192.927, and 192.929
- Remediation meeting the requirements of 192.933
- Continual Evaluation and Assessment meeting requirements of 192.937
- Confirmatory DA meeting requirements of 192.931
- Preventive and Mitigative Measures meeting requirements of 192.935
- Performance Measures as outlined in ASME/ANSI B31.8S and meeting requirements of 192.945
- Recordkeeping meeting requirements of 192.947
- Management of Change as outlined in ASME/ANSI B31.8S section 11
- Quality Assurance as outlined in ASME/ANSI B31.8S section 12
- Communications Plan that includes elements of ASME/ANSI B31.8S section 10
- Submittal of program documents to the OPS and any state pipeline safety authority when a covered segment is in a state where OPS has an interstate agent agreement
- Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
- A process for identification and assessment of newly-identified high consequence areas per 192.906 and 192.921

3.1.4 Baseline Assessment Plan

The Baseline Assessment Plan (BAP) will be used by the operator to assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. The following methods are recommended to assess the integrity of the line pipe:

- Internal Inspection Tool or tool that is capable of detecting corrosion and any other threats to which the covered segment is susceptible. ASME/ANSI B31.8S are to be used to determine which internal inspection tool is most appropriate for the line segment
- Pressure Test as specified in ASME/ANSI B31.8S in Table 3 of Section 5 in order to justify an extended reassessment interval in accordance with 192.939
- Direct Assessment to address threats of External Corrosion (EC), Internal Corrosion (IC), and Stress Corrosion Cracking (SCC). The Direct Assessment must be conducted in accordance with the requirements listed in 192.923

An operator is permitted to use other technology if it can provide an equivalent assessment of the pipe's condition. If this option is chosen, the operator must inform OPS 180 days before conducting the assessment in accordance with 192.949.

A prior assessment can be used as the BAP as long as the assessment was completed before December 17, 2002, the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions in 192.933 have been carried out. Also, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of 192.937 and 192.939.

3.1.5 Direct Assessment

Direct Assessment can be used as a primary tool or as a supplement to any other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of External Corrosion

(ECDA), Internal Corrosion (ICDA), and Stress Corrosion Cracking (SCCDA).

External Corrosion Direct Assessment (ECDA) is a four (4) step process that combines pre-assessment, indirect assessment, direct examination and post assessment to evaluate the threat of external corrosion to the integrity of the pipeline. When ECDA is applied for the first time on a covered segment, the operator must select two different but complementary indirect assessment tools to assess the ECDA region.

Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas.

Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

49 CFR Part 192 Subpart O gives the basic requirements and regulations an operator must perform and comply with in order to assess pipeline integrity on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.

3.1.6 Regulatory Interpretations

Regulatory interpretations are listed on such websites as the Pipeline Hazardous Materials Safety Administration (http://www.phmsa.dot.gov). Frequently Asked Questions, or FAQs, are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. There is a FAQ section for Natural Gas as well as Hazardous Liquid Pipelines. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

Both the OPS website and information telephone line are staffed by OPS engineers and regulatory personnel. OPS staff are available between the hours of 9:00 a.m. and 5:00 p.m. Eastern time, Monday through Friday, except Federal holidays. The OPS telephone number and OPS website address are provided in customer brochures. Callers are directed to the information telephone line through the main telephone line at OPS headquarters. Both services are accessible on a 24-hour basis. Individuals may leave a recorded voicemail message by telephone or post a message at the website when OPS personnel are not present. All messages will receive a response by the following business day. The telephone number for the OPS information line is (202) 366-0918 and the OPS website can be accessed via the Internet at http://www.dot.ops.gov.

The Office of Chief Counsel (OCC) is also available to answer questions concerning pipeline safety law, the statutory authority underlying Research and Specialty Programs Administration's (RSPA) pipeline regulations. The OCC may be contacted by telephone (202-366-4400) from 9:00 a.m. to 4:00 p.m. Eastern time, Monday through Friday, except Federal holidays. Information and guidance concerning pipeline safety law may also be obtained by writing to OCC or by contacting OCC via the Internet at http://rspa-atty.dot.gov. OCC's website contains, or will soon contain: an organizational list; an index to preemption of state and local laws on hazardous materials transportation; the status of preemption determination applications; "hot topic" summaries of current significant decisions and events; procedural rules for pipeline safety administrative enforcement cases; and, a "feedback" mechanism to correspond electronically with OCC staff attorneys.

Requests for informal interpretations regarding the applicability of one or more of the pipeline integrity management rules to a specific situation may be submitted to PHMSA in accordance with 49 CFR Part 190.11. This section:

- Sets out the availability of assistance via the OPS and OCC websites on the internet and by telephone with respect to pipeline safety issues
- Provides the OPS and OCC website internet addresses

- Provides OPS and OCC telephone numbers

RSPA has designated its website on the internet and a telephone line in its Washington, D.C. headquarters as its primary means of disseminating information concerning small pipeline operators. OPS regional offices and inspectors in the field will also disseminate information and provide assistance to small operators. Small operators can access information on pipeline safety regulations, recent Federal Register notices, interpretations, waivers, Alert Notices, and other useful information.

To illustrate the point of this section, examples of interpretations by OPS on Section 192.465 follow:

- So long as any type of inspection that the operator makes assures that a rectifier is operating satisfactorily as required by sections 195.416 and 192.465, it is immaterial to OPS as to how that objective is accomplished.
- For liquid pipelines, Section 195.416, and gas pipelines, Section 192.465, a company must inspect each of its cathodic protection rectifiers at intervals not to exceed two months to ensure that each rectifier is operating.
- Active corrosion means continuing corrosion, which unless controlled, could result in a condition that is detrimental to public safety.
- Active corrosion could be detected by a pipe-to-soil potential survey or a surface potential survey for “hot spots.” However, where an electrical survey cannot be made (Section 192.465(e)), the operator shall determine the presence of active corrosion by a study of leak history records, a leak detection survey or any other means that would give knowledge as to where pipe has been failing due to corrosion.
- Section 192.465 requires tests on separately protected service lines once every ten years, including meter risers where the metal is the gas carrier and the metal piping extends below the ground surface. Subpart I — requirements for corrosion control must also be complied with. This mandates that operators of such piping to monitor these short sections as required in 192.465(a).

- Pipelines that are voluntarily cathodically protected are not subject to the monitoring requirements of 192.465. An anode installed on a non-corrosion leak repair would not have to be recorded, unless the leak occurred in an area where cathodic protection is required by 192.465(e) because of active corrosion in the area.
- Inspection guidelines for 192.465 states that each operator shall take prompt remedial action to correct any deficiencies indicated by monitoring. The definition of "prompt" will vary with the circumstances. If an operator's established time frame for action is considered inadequate, it is a violation of 192.465(d). If the operator has no procedure for promptly responding and deficiencies exist, it is a violation.

References

1. http://www.gpoaccess.gov/cfr/index.html
2. http://ops.dot.gov/init/init.htm
3. http://hazmat.dot.gov/riskmgmt/riskprog.pdf
4. http://www.phmsa.dot.gov/about/index.html
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7. http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=2141b97597c0d1d70d592421a490600c&rgn=div5&view=text&node=49:3.1.1.1.3&idno=49#49:3.1.1.1.3.15
8. http://ops.dot.gov/regs/2001/part195.htm

Chapter 4: Standards

After completing this chapter, students should be able to:

- Identify the primary relevant standards and guidelines relating to Pipeline Corrosion Integrity Management.
- Determine which standards are applicable to specific aspects of an integrity management program.
- Have a basic understanding of the purpose and major aspects of a particular primary relevant standard.

A strong working knowledge of the relevant standards and guidelines is essential and should be an integral component of every Pipeline Corrosion Integrity Management plan. Many standards relating to Pipeline Corrosion Integrity Management are evolving and additional standards are being developed. Therefore, it is essential to stay abreast of advancing technology and the available resources, and to amend the integrity management program as appropriate.

4.1 Summary of Standards

Primary standards relating to Pipeline Corrosion Integrity Management include:

- ASME B31.8S, American Society of Mechanical Engineers, “Managing System Integrity of Gas Pipelines.”
- API 1160, American Petroleum Institute, “Managing System Integrity for Hazardous Liquid Pipelines.”
- NACE SP0502, NACE International Standard Recommended Practice, “Pipeline External Corrosion Direct Assessment Methodology.”
- Proposed NACE Internal Standard Recommended Practice, “Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA).”
- NACE SP0204, NACE International Standard Recommended Practice, “Stress Corrosion Cracking (SCC) Direct Assessment Methodology.”

- NACE SP0102, NACE International Standard Recommended Practice, "In-Line Inspection of Pipelines."
- CSA Z662, Canadian Standards Association Standard, "Oil and Gas Pipeline Systems."

Other standards and guidelines pertaining to Pipeline Corrosion Integrity Management include:

- GRI-00/0189, Gas Research Institute, "Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines."
- GRI-00/0231, Gas Research Institute, "Direct Assessment and Validation."
- GRI-04/0093.6, Gas Technology Institute, "Practical Guidelines for Conducting an External Corrosion Direct Assessment Program."
- API 570, American Petroleum Institute, "Piping Inspection Code: Inspection, Repair, Alteration, and Reconstruction."
- NACE SP0169, NACE International Recommended Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems."
- NACE TM0497, NACE International Standard Test Method, "Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems."
- CSA Z662-03, Canadian Standards Association, "Oil and Gas Pipeline Systems."
- BS 7910, British Standard, "Guide on Methods for Assessing the Acceptability of Flaws in Metallic Structures."
- API 579, American Petroleum Institute, "Fitness for Service."
- DNV RP-F101, Standard Recommended Practice, "Corroded Pipelines."
- ASME B31G, American Society of Mechanical Engineers, "Manual for Determining the Remaining Strength of Corroded Pipelines – A Supplement to B31, Code for Pressure Piping."

- NACE International Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
- ASTM E709, "American Society of Testing and Materials Standard Guide for Magnetic Particle Inspection."
- Canadian Energy Pipeline Association (CEPA), "Stress Corrosion Cracking Recommended Practices Manual."
- NACE International Publication 35100, "In-Line Nondestructive Inspection of Pipelines."
- GRI-00/0247, Gas Research Institute, "Introduction to Smart Pigging In Natural Gas Pipelines."

4.1.1 ASME B31.8S – Managing System Integrity of Gas Pipelines

ASME B31.8S applies to onshore pipeline systems constructed with ferrous materials that transport gas. The standard provides the fundamentals to develop and implement an effective integrity management program. It covers both prescriptive and performance based processes. Primary areas addressed by ASME B31.8S include:

a) Principles of an Integrity Management Program for gas pipelines

b) Classification of potential threats to pipeline integrity

c) Data gathering, analysis and integration

d) Sub-plans that form the overall program – performance, communication, quality control, and management of change

e) Assessment of risk as a function of the likelihood and consequence of a pipeline failure

f) Integrity assessment techniques – in-line inspection tools, pressure testing, external corrosion direct assessment, and internal corrosion direct assessment

g) Repair and prevention responses to integrity assessments and mitigation, including a comprehensive listing of acceptable methods

h) Sample integrity management plan (hypothetical pipeline segment)

i) Program review and revision (as necessary) as pipeline integrity is determined

j) Related references and standards

4.1.1.1 General

The general requirements for a gas pipeline integrity management program are outlined in Section 2 of ASME B31.8S. In this code (standard) an onshore pipeline system is defined as all of the physical facilities that transport gas. This includes pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies. The various aspects of integrity management are applicable to all of these facilities.

ASME B31.8S provides the pipeline operator with information to develop and implement an effective integrity management program using proven industry practices and processes. The procedures allow a pipeline operator to assess and mitigate risks in order to reduce both the likelihood and consequences of incidents. The program elements depicted in Figure 4.1 are required for all integrity management programs.

ASME B31.8S is a supplement to the ASME B31.8 Code, Gas Transmission and Distribution Piping Systems. To effectively manage the integrity of a gas pipeline system is a primary goal of every pipeline operator, and to provide safe and reliable delivery to their customers without adverse effects on employees, the public, customers, or the environment. A comprehensive, systematic, and integrated integrity management program provides a means to safely operate a pipeline, making improvements as necessary, based on a solid technical foundation. An effective integrity management program allows for suitable allocation of resources for appropriate prevention, detection, and mitigation activities.

Details of the integrity management process are reviewed in Section 2.4 of ASME B31.8S. Gas pipeline integrity management is addressed through both prescriptive-based performance-based approaches. The prescriptive process, when followed explicitly, provides for all the inspection, prevention, detection and mitigation activities necessary. Use of a prescriptive approach does not preclude conformance with ASME B31.8. In a performance-based approach, more data is gathered and more extensive risk analyses are conducted. This enables the operator to achieve a greater degree of flexibility to meet or exceed the requirements of the standard, specifically as related to inspection intervals, tools used, and mitigation techniques. An operator cannot proceed with a performance-based integrity program until adequate inspections are performed that provide information on pipeline condition required by the prescriptive-based program. The level of assurance of a performance-based program or an alternative international standard must meet or exceed that of a prescriptive program.

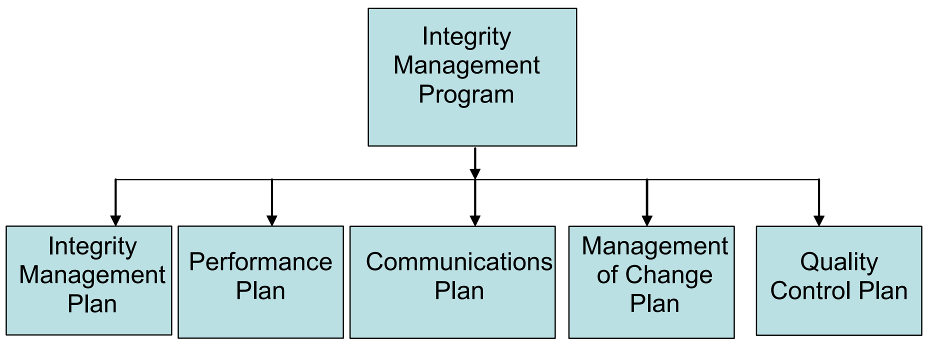


Figure 4.1 Integrity Management Program Elements

4.1.1.2 Data Gathering and Integration

Information gathering and integration are key aspects for managing system integrity. Specifics are covered in Section 4 of ASME B31.8S. Table 4.1 from ASME B31.8S lists data elements for a prescriptive integrity program. While there is no standard list for performance-based programs, increasingly complex risk assessment methods for such programs often require considerably more data.

Sources of data needed for integrity management programs are varied and can be obtained from within an operating company and from external sources, e.g., industry-wide data. Table 4.2 lists some typical sources.

Table 4.1: Data Elements for Prescriptive Pipeline Integrity Program

Attribute data	
• Pipe wall thickness • Diameter • Seam type and joint factor • Manufacturer	• Manufacturing data • Material properties • Equipment properties
Construction	
• Year of installation • Bending method • Joining method, process and inspection results • Depth of cover • Crossings / casings	• Pressure test • Field coating methods • Soil, backfill • Inspection reports • Cathodic protection installed • Coating type
Operational	
• Gas quality • Flow rate • Normal maximum and minimum operating pressures • Leak / failure history • Coating condition • Cathodic protection performance • Pipe wall temperature	• Pipe inspection reports • OD / ID corrosion monitoring • Pressure fluctuations • Regulator / relief performance • Encroachments • Repairs • Vandalism • External forces
Inspection	
• Pressure tests • In-line inspections • Geometry tool inspections • Bell hole inspections	• Cathodic protection inspections, e.g., close interval survey (CIS) • Coating condition inspections, e.g., direct current voltage gradient survey (DCVG) • Audits and reviews

4.1.1.3 Risk Assessments and Pipeline Threats

A critical part of an integrity management program is understanding and managing risk for different pipeline segments. Risk assessments are required for both prescriptive- and performance-based programs.

As part of risk analysis, it is important to determine the area of influence should a failure occur. ASME B31.8S Section 3 defines the "radius of impact" for a natural gas line as:

$$r = 0.69 \times d \times p0.5$$

Where:

r = radius of impact, in feet

d = outside diameter of pipe, in inches

p = pipeline segment's maximum allowable operating pressure (MAOP), in psig

Table 4.2: Typical Data Sources for Pipeline Integrity Program

• Process and instrumentation drawings (P&ID)	• Industry standards / specifications
• Pipeline alignment drawings	• O&M procedures
• Original construction inspector notes / records	• Emergency response plans
• Pipeline aerial photography	• Inspection records
• Facility drawings / maps	• Test reports / records
• As-built drawings	• Incident reports
• Material certifications	• Compliance records
• Survey reports / drawings	• Design / engineering reports
• Safety related condition reports	• Technical Evaluations
• Operator standards / specifications	• Manufacturer equipment data

One of the first steps in managing pipeline integrity is identifying potential threats. Based on an analysis of gas pipeline incident data, Pipeline Research Council International, Inc. has classified the threats into 22 root causes, 21 that can be specifically defined and the 22nd being “unknown.” The primary 21 threats are grouped into nine categories as listed in Table 4.3.

It is important that performance metrics be established and documented for each pipeline threat, and that these metrics be periodically revisited as additional data is gathered and analyzed.

4.1.1.4 Risk Analysis and Consequences

Section 5 of ASME B31.8S covers risk assessment. In this section, the mathematical definition of risk is the product of the likelihood (probability) and the consequences of events that result from a failure. One method of determining risk for a particular pipeline segment is:

$Risk_i = P_i \times C_i$, for a single threat

Risk = (Pi x Ci) for threat categories 1 through 9

$$\text{Total segment risk} = (P1 \times C1) + (P2 \times C2) + \ldots + (P9 \times C9)$$

Where:

C = failure consequence

P = failure likelihood, i.e., probability

I = failure threat category, 1 through 9

Table 4.3: Time-Dependant Factors and Failure Mode Grouping

• Time Dependent:
- External corrosion (Category 1)
- Internal corrosion (Category 2)
- Stress corrosion cracking (Category 3)
 	
• Stable:
- Manufacturing defects (Category 4):
  - Pipe seam
  - Pipe
- Welding/fabrication defects (Category 5):
  - Pipe girth weld
  - Fabrication weld
  - Wrinkle bend or buckle
  - Stripped threads/broken pipe/ coupling failure
	• Stable *(continued)*
	- Equipment (Category 6):
	  - Gasket O-ring failure
	  - Control / relief equipment malfunction
	  - Seal / pump packing failure
	  - Miscellaneous
	
	• Time Independent:
	- 3rd party / mechanical damage (Category 7):
	  - Damaged inflicted by 1st, 2nd or 3rd parties resulting in instantaneous/immediate damage
	  - Previously damaged pipe (delayed failure mode)
	  - Vandalism
	- Incorrect operational procedure (Category 8)
	- Weather related and outside forces (Category 9)

Consequence factors to consider include those in Table 4.4.

Table 4.4: Pipeline Integrity Consequence Factors

• Population density • Proximity of the population to the pipeline, including man-made and natural barriers that may provide some protection • Property damage • Environmental damage • Effects of un-ignited gas releases	• Security of gas supply, e.g., impacts resulting from interruption of service • Public convenience and necessity • Potential for secondary failures • Richness of transported gas and how the gas decompresses; these factors impact the significance of defects and material properties when modeling a failure

4.1.1.5 Prevention and Repair Methods

Once potential threats are defined and pipe condition is determined, establish prevention and repair methods. Table 5-4 in ASME B31.8S (Section 7) provides a comprehensive listing of available prevention and repair methods sorted by threat category.

4.1.1.6 Program Review and Revision

Section 9 and subsequent sections of ASME B31.8S present guidelines and metrics to monitor the performance of the integrity management program for a gas pipeline system. It is important to recognize that pipeline integrity management is a living process. As data is gathered and pipeline operations continue, it is important to routinely:

- communicate with stakeholders
- manage changing conditions
- maintain quality control

Formalized plans for each of these ongoing activities are essential.

4.1.2 API 1160 – Managing System Integrity for Hazardous Liquid Pipelines

API 1160 is a very comprehensive guide for pipeline systems that transport hazardous liquids as defined in Title 49 CFR 195.2 of the federal pipeline safety regulations. It provides a solid foundation to address integrity management of pipelines under the jurisdiction of Title 49 CFR 195.2. The basic theme and processes established in API 1160 for hazardous liquid pipelines are comparable to those in ASME B31.8S for natural gas pipelines.

Primary areas addressed by API 1160 include:

a) Identification and documentation of High Consequence Areas (HCAs) and the influence of pipeline segments on these areas

b) Data gathering, analyses, and integration, including a comprehensive listing of the types of data to collect

c) Risk assessment, validation and prioritization

d) Initial baseline assessment plan development and implementation

e) Determination of subsequent inspection interval/frequency

f) Pipeline anomaly types and tools for detection

g) Mitigation options and repair methods, including a comprehensive listing of commonly used permanent pipeline repair techniques

h) Preventative and rehabilitation measures

i) Detection and minimization of pipeline releases

j) Integrity management of pipeline pump stations and terminals, including mitigation options, design considerations, corrosion control and tanks

k) Performance measures and audits

l) Managing change and updating the pipeline integrity program

m) Comprehensive appendices on anomaly types/causes/concerns and repair strategies

n) Standard data entry fields

4.1.2.1 Regulatory Requirements

As summarized in the Foreword of API 1160, this standard was developed in response to amendments to 49 CFR 195 about Pipeline Integrity Management In High Consequence Areas. This rule (49 CFR 195.452) became effective May 29, 2001. Its purpose is to enhance and validate hazardous liquid pipeline integrity, and to provide improved protection for high consequence areas (HCAs) that could be affected by an unintended release. Operators of 500+ miles of hazardous liquid pipeline must comply with CFR 195.452.

High consequence areas are defined in 49 CFR 195.450 as:

- A high population area that contains 50,000 or more people and has a population density of at least 1,000 people per square mile
- Other populated areas with a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area
- A commercially navigable waterway
- An environmental or other area that has been designated as unusually sensitive to oil spills (an "unusually sensitive area," or USA), as defined by 49 CFR 195.6

The hazardous liquid pipeline integrity rule requires the following elements be incorporated into an integrity management program, guidelines for which are covered in API 1160:

- Process for determining pipeline segments that could affect HCAs
- Baseline assessment plan
- Periodic integrity assessment and evaluation of pipeline segments that could affect HCAs
- A risk assessment process whereby all available integrity data and consequences of a failure are thoroughly analyzed
- Repair and mitigation measures to address issues identified by the integrity assessment method

- Process to identify and evaluate prevention and mitigation measures to protect HCAs
- Methods to measure the effectiveness of the integrity management program
- A process for review of integrity management results and data analysis by a qualified individual
- Recordkeeping, including documented technical justification for key integrity management decisions and for any allowed variations or deviations

4.1.2.2 Guiding Principles

As described in Section 1.2 of the standard, API 1160 is based on the following guiding principles:

- Integrity must be built into pipeline systems from initial planning, design, and construction.
- System integrity is built on qualified people using defined processes to operate maintained facilities.
- An integrity management program must be flexible, including having multiple options available to address risks.
- Information integration in the decision making process is key for managing system integrity.
- Preparing for and conducting a risk assessment is a key element.
- Risk assessment is a continuous process.
- Mitigation actions are taken for injurious defects.
- New technology should be evaluated and utilized as appropriate.
- Pipeline system integrity and integrity management programs should be evaluated regularly.

4.1.2.3 API 1160 Integrity Management Program

Figure 4.2 is reprinted from API 1160 (Section 5) and illustrates a common framework for developing an operator-specific integrity management program. Programs should be developed based on specific (unique) integrity management goals and objectives.

Established procedures in conjunction with new procedures as necessary should be used to assure the goals and objectives are met.

API 1160 emphasizes the importance of an integrated and iterative process to assure an effective integrity management program. Continuous feedback and updating of information often requiring several iterations are essential until an operator is satisfied that the risk assessment adequately characterizes pipeline system risk.

Referencing Figure 4.2, specific elements of the integrity management program process set by API 1160 include:

- ***Identification of potential pipeline impacts to HCAs*** – This involves locating facilities and conditions on a map in conjunction with the pipeline route to determine at which locations a release could impact the HCAs.
- ***Initial data gathering, review and integration*** – This step is intended to collect, analyze and integrate sufficient data on pipeline condition and identify location-specific threats to pipeline integrity. The data are gathered on a pipe segment by pipe segment basis. Key information is derived from pipeline design records, operation/maintenance/surveillance practices, operating history, and specific failure modes and concerns. Typically, the data to be collected can be divided into five main categories:
  - Design, material, and construction data
  - Right of way data
  - Operation, maintenance, inspection and repair data
  - Records to determine if specific pipeline sections may affect sensitive areas
  - Incidents and risk data
- ***Initial risk assessment*** – This is perhaps one of the most critical and most subjective components of the integrity management process. Determine risk with a systematic and comprehensive search for possible threats to pipeline and facility integrity. In addition to traditional risk categories, take steps to identify new or unique risk considerations. Once the threats have been identified, the next step is to identify possible risk control and mitigation options for each pipeline segment. The extent of risk assessment will vary significantly among operators depending on the sophistication of their processes. Figure 4.3 is a simple

depiction of a risk-based engineering approach to determine and manage pipeline integrity. The overall risks of a pipeline system or individual segments are determined on the likelihood that an event or condition could lead to a release (e.g., severe corrosion damage) and what the consequences would be (e.g., crude entering a waterway). You must consider the likelihood and consequences of a release when you conduct a risk assessment and make prudent risk-based decisions.

- ***Development of baseline assessment plan*** – At this point use the data gathered to develop a plan to address the most significant risks and determine the integrity of the pipeline in these high risk areas. 49 CFR 195.452 requires that a documented plan be prepared for pipeline segments that could affect HCAs. The plan must include the internal inspection techniques, pressure testing, and/or other technologies to be used. The plan must also include an assessment schedule and the basis for the particular assessment techniques that will be used. API 1160 includes the following condition assessment techniques:

  - Internal inspection and testing – metal loss tools, crack detection tools, geometry tools.
  - Hydrostatic testing.

- ***Inspection and mitigation*** – This phase implements the baseline assessment plan. It includes identifying and eliminating defects that might lead to pipeline failure as well as improvements to operation and maintenance procedures to control risk. Appendix B in API 1160 provides a comprehensive description of commonly used repair techniques, including cathodic protection, coating rehabilitation, pipeline maintenance cleaning, plus leak detection and control.

- ***Update, integrate, and review data*** – This is an on-going process in which data is continually updated and added to document the status of pipeline integrity and aid in future risk assessments and integrity evaluations. Documenting O&M knowledge and experience is an essential part.

- ***Reassessment of risk*** – Risk impacts should be reviewed regularly to identify changes and additions that could decrease pipeline integrity. Examples include new valves, changes in hydraulic pressure, and population encroachment in new areas. Risk considerations and pipe condition updates should be built into future assessments so that the process will always provide the most accurate snapshot of the pipeline's condition.

- ***Revise mitigation and inspection plan*** – You must also review and update the mitigation and inspection plans periodically. You should identify any new risks and what actions were taken to control previously identified risks. Use updates to the plan to determine the schedule for subsequent integrity assessments.

- ***Program evaluation*** – Periodic audits of the integrity management program allow you to gauge its success and determine areas for improvement. The evaluation should include integrity assessment techniques, repair procedures, and other risk prevention and control strategies. It should also include an evaluation of the integrity management systems and processes to verify it still promotes sound integrity management decisions.

- ***Management of change*** – Another must is a systematic process to identify and manage change, incorporating design, operation and maintenance information as well as data about surrounding facilities and environment. I cannot over emphasize that *managing pipeline integrity is not a one-time process – it is a continuous cycle* of monitoring pipeline conditions, identifying and assessing risks, and taking action to adequately control the most significant threats.

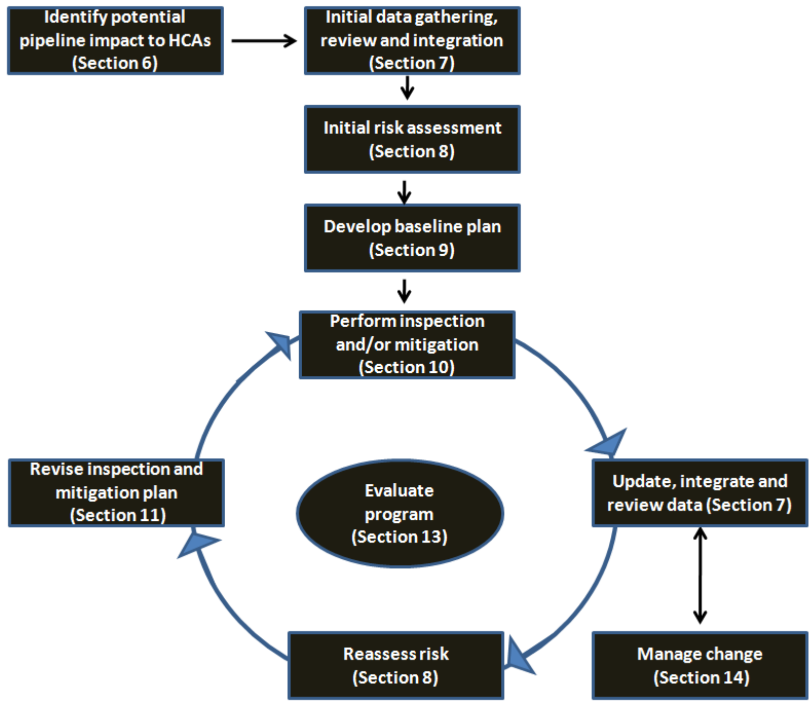


Figure 4.2 Framework for an Integrity Management Program

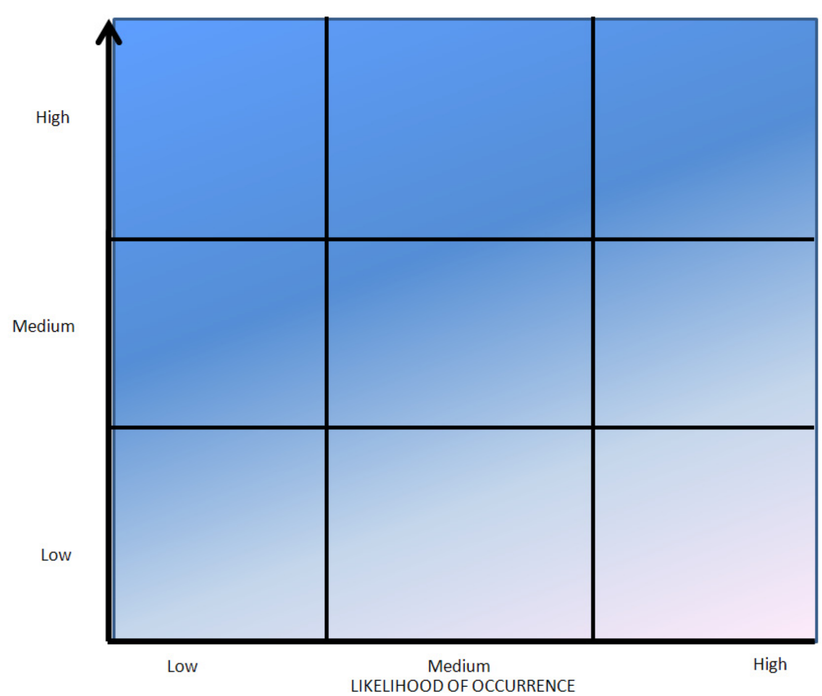


Figure 4.3 Simplified Depiction of Risk

4.1.3 NACE International SP0502 – Pipeline External Corrosion Direct Assessment Methodology

NACE SP0502 provides a guide for external corrosion direct assessment (ECDA) for buried onshore ferrous piping systems. As summarized in Section 1 of NACE SP0502, this recommended practice is applicable to gas, hazardous liquids, water, wastewater, and other regulated and non-regulated pipelines. A continuous improvement can be instrumental in detecting pipeline integrity threats including pitting corrosion, mechanical damage, stress corrosion cracking, and microbiologically influenced corrosion (MIC). ECDA applications include but are not limited to pipeline segments that cannot be reliably inspected using in-line inspection tools, pressure testing, or other inspection tools. ECDA can also be used in combination with these inspection methods to manage future corrosion.

Primary areas addressed by NACE SP0502 include:

a) The four steps of the ECDA process – pre-assessment, indirect inspection, direct examination, and post-assessment

b) Data collection elements, including pipe-related, construction-related, soils/environment, and operations

c) Feasibility and limitations of ECDA assessment

d) Identification of ECDA regions

e) Comprehensive information on indirect inspection tools, procedures, and data interpretation, including close interval pipe-to-soil potential surveys, AC and DC voltage gradient surveys, Pearson coating fault surveys, electromagnetic surveys, AC current attenuation surveys, and soil corrosivity investigations

f) The use of at least two indirect inspection tools/techniques to reliably determine direct examination locations

g) Direct examination procedures including prioritizing threats and guidelines to determine quantity of and locations for excavation/inspections

h) Root cause analysis for and mitigation of significant corrosion activity detected

i) Remaining life calculations

j) Reassessment intervals

k) ECDA effectiveness, feedback and continuous improvement

Pre-Assessment (Phase 1)

Section 3 of NACE SP0502 outlines the first phase of the ECDA process, Pre-Assessment. In this phase, a sufficient amount of data collection, integration and analysis is required. Pre-assessment is directed toward determining:

- Whether ECDA is feasible for the particular pipeline being evaluated
- Selection of indirect inspection tools
- Identification of ECDA regions along the pipeline

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

Historical and current data to be gathered as part of Pre-Assessment are grouped into five main categories:

- ***Pipe related*** – material, diameter, wall thickness, seam type, coating type (if any), other
- ***Construction related*** – year installed, route including any changes, route maps and aerial photos, construction practices, location of appurtenances, other
- ***Soils/environmental*** – soil characteristics and type, drainage, topography, current and past land use, potential for frozen ground, other
- ***Corrosion control*** – cathodic protection details including test points, criteria and current demand, stray current influences, cathodic protection maintenance history and data including any periods without cathodic protection, coating quality, other
- ***Operational data*** – operating temperature, operating stress levels and fluctuations, monitoring programs such as electrical resistance and weight loss corrosion coupons, patrols and leak

surveys, pipe inspection/excavation reports, repair history and records, leak/rupture history, evidence of microbiologically influenced corrosion, third party damage, earlier over-the-ground and surface surveys, hydrostatic test dates and pressures, and other prior integrity assessment procedures such as close interval surveys and in-line inspections

After analyzing the above data, you determine the feasibility of ECDA and any possible limitations. Limiting conditions include electrical shielding, backfill with significant rock content or rock ledges, certain ground conditions such as pavement, frozen ground, reinforced concrete, and inaccessible areas, among others.

If conditions along a certain pipeline segment or region are such that indirect inspections or alternative methods to determine pipe integrity can't be used, then the ECDA procedures set forth in NACE SP0502 are not appropriate.

Based on the data analysis and feasibility determination, you then decided on the specific indirect inspection tools you will use. ECDA requires a minimum of two tools (procedures) be used for each pipeline region to be evaluated. The more common tools include:

- Close interval potential survey (CIS)
- Direct and alternating current voltage gradient surveys (DCVG and ACVG)
- Pearson coating fault surveys
- Electromagnetic coating fault surveys
- AC current attenuation surveys

Each of these procedures has advantages and disadvantages. Table 2 in NACE SP0502 provides a well defined ECDA tool selection matrix that addresses the applicability and more common constraints for each procedure.

Figure 4.4 is reprinted from NACE SP0502 and illustrates factors that influence the type of indirect inspection tools to be used for different ECDA regions along a hypothetical pipeline.

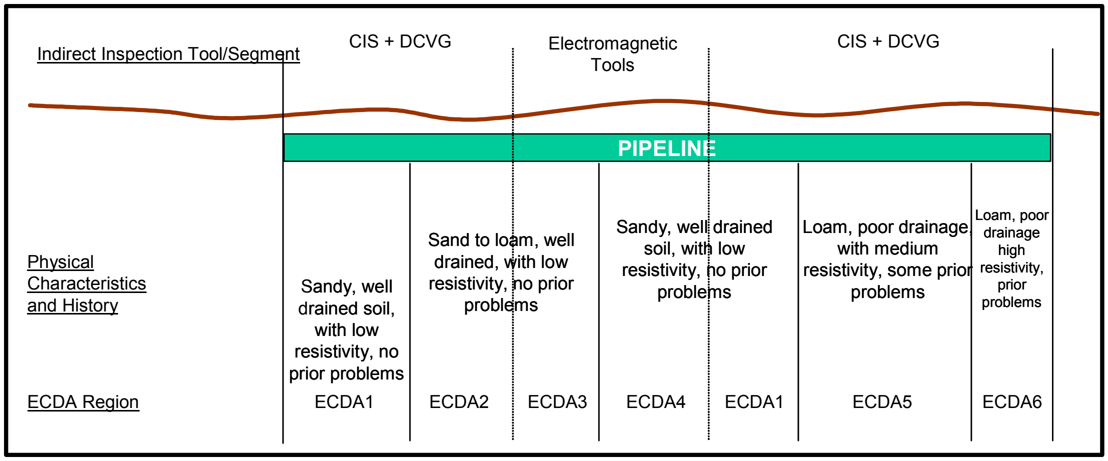


Figure 4.4 Illustration of ECDA Region Definitions

In lieu of an ECDA protocol requiring indirect inspections and direct examinations at select locations, the pipeline operator may substitute 100% direct examination. Extensive data gathering that must be part of the 100% direct examination includes:

- Pipe-to-soil potentials
- Soil resistivity measurements
- Laboratory analysis of soil samples to determine corrosivity factors, e.g., moisture content, chloride ion concentration, and pH
- Analysis of microbiologically influenced corrosion factors
- Corrosion product analysis
- Coating type and characteristics, e.g., condition and adhesion
- Corrosion and defect identification and mapping
- Corrosion rate testing

Indirect Inspections (Phase 2)

Section 4 of NACE SP0502 outlines the second phase of the ECDA process, Indirect Inspections. For this phase, indirect inspection tools (listed previously in this chapter) and/or others are used on the clearly defined pipeline regions which were determined during pre-assessment. Indirect inspections are used to identify and define the severity of coating faults, other anomalies, and areas at which corrosion activity may have already occurred or may be occurring.

Using at least two indirect procedures within each region, the data is analyzed and aligned for comparison. If analysis of the data from the differing indirect procedures suggests changed pipe conditions, then additional procedures should be used to resolve any disparities which may include spot excavations.

You should classify pipe anomalies discovered by indirect inspection according to risk severity. Typical classifications are:

- ***Severe*** – pipeline operator thinks the specific location has the highest likelihood of corrosion
- ***Moderate*** – pipeline operator thinks the specific location possibly has corrosion
- ***Minor*** – pipeline operator thinks the specific location is inactive or has the lowest likelihood of corrosion

Establish well-defined criteria to determine severity. When ECDA is used the first time, the classification criteria should be as stringent as practicable. When the likelihood of corrosion can't be determined, the specific location should be classified as "severe."

Table 4.5 reprinted from NACE SP0502 illustrates how indications from different indirect inspection methods are used to determine severity classification.

Table 4.5: Example Severity Classification

Tool/Environment	Minor	Moderate	Severe
CIS, aerated moist soil	Small dips with on and off potentials above CP criteria	Medium dips or off potentials below CP criteria	Large dips or on and off potentials below CP criteria
DCVG Survey, similar conditions	Low voltage drop; cathodic conditions at indication when CP is on and off	Medium voltage drop and or neutral conditions at indication when CP is off	High voltage drop and or anodic conditions when CP is on and off
ACVG or Pearson survey, similar conditions	Low voltage drop	Medium voltage drop	High voltage drop
Electromagnetic	Low signal loss	Medium signal loss	Large signal loss

Table 4.5: (Continued) Example Severity Classification

AC current attenuation surveys	Small increase in attenuation per unit length	Moderate increase in attenuation per unit length	Large increase in attenuation per unit length

Direct Examinations (Phase 3)

Section 5 of NACE SP0502 outlines the third phase of the ECDA process, Direct Examinations. In this phase, locations for excavations and direct examinations are determined by the results of the indirect inspection analysis. The objectives are to determine which indications from the indirect inspections are most severe and to collect sufficient additional data to assess corrosion activity.

The priority for direct examinations is classified as:

- ***Immediate*** – when indications suggest an immediate threat to pipeline integrity under normal operating conditions
- ***Scheduled*** – when indications suggest ongoing corrosion that does not pose an immediate threat to pipeline integrity
- ***Suitable for monitoring*** – when indications suggest inactive conditions or the lowest likelihood of ongoing or prior corrosion

Main activities included in Direct Examination are:

- Prioritizing indications from indirect inspections
- Excavation/inspections and data collection at areas where corrosion is most likely
- Measurement of coating damage and corrosion deterioration
- Evaluation of remaining strength using procedures such as ASME B31.G and RSTRENG
- Root-cause analysis of any coating damage and/or corrosion deterioration
- An evaluation of the process

A minimum of one excavation/inspection is required within each ECDA region. Additional excavation/inspections are needed when there are more locations identified during Pre-Assessment to be the most likely sites for external corrosion, and when extensive corrosion is detected at the first location. Corrosion deeper than

20% of the original wall thickness and deeper or more severe than at an immediate indication warrants at least one more direct examination.

Post-Assessment (Phase 4)

Section 6 of NACE SP0502 outlines the fourth phase of the ECDA process, Post-Assessment. This phase of ECDA includes:

- An analysis to define the reassessment interval
- A review of the overall effectiveness of the pipeline-specific ECDA process

Remaining life calculations are an integral part of post-assessment. From this data, the time to the next reassessment is conservatively determined as half that value.

To determine the effectiveness of ECDA, make at least one additional direct examination at a randomly selected location to validate the process. In instances where corrosion is found to be more severe than at other indications, the repeat and reevaluate the process, or use an alternative integrity assessment method.

Another procedure to evaluate ECDA effectiveness is system tracking to determine if there is an overall increase in threats to pipeline integrity; if an increase is evident for more frequent reassessment may be necessary.

As with other pipeline integrity protocols, feedback and continuous process improvements are an integral part of ECDA.

4.1.4 NACE SP0206 – Dry Gas ICDA

When finalized, this NACE International document will formalize the DG-ICDA methodology. The underlying logic for DG-ICDA is that a detailed internal examination of locations where water would first accumulate provides critical information about internal conditions downstream. DG-ICDA provides the greatest internal corrosion assessment benefit for pipelines that cannot support in-line inspection; however, the method is not limited to pipelines in this category.

The proposed NACE International DG-ICDA document includes:

a) Details of the four-step process:

- Pre-assessment, including records review, current operating data and DG-ICDA feasibility.
- Indirect inspection, including multiphase flow predictions and identifying where internal corrosion may be present
- Detailed examination, including excavations and procedures to determine whether metal loss from internal corrosion has occurred
- Post-assessment, including data analysis and determination of reassessment intervals

b) Essential data for DG-ICDA methodology

c) Flow modeling calculations

d) Related standards and methods for nondestructive inspection techniques

e) Criteria to quantify significant internal corrosion metal loss and methods to calculate remaining pipe strength where corrosion is found

f) Validation

g) Recordkeeping

h) Sample DG-ICDA application

In concept, the four steps of DG-ICDA follow those of ECDA. The two procedures primarily differ in the types of data collected under Pre-Assessment, identification of DG-ICDA regions, and the methodology for Indirect Inspections.

Pre-Assessment

Accurate and complete elevation profiles, flow rate data, and pressure history are key to the DG-ICDA process. This information is essential to predict the locations of possible liquid holdups, which is the primary objective of DG-ICDA.

The different categories of data and the types of data to be collected during pre-assessment are summarized in Table 4.6.

Table 4.6: Essential Data for Use of DG-ICDA Methodology

Operating history	Change in gas flow direction, type of service, removed taps, year of installation, etc. Has the line ever been used previously for crude oil or other liquid products?
Defined length	Length between inputs/outputs.
Elevation profile	Topographical data (e.g., USGA (1) data,) including consideration of pipeline depth of cover. Take care in instrument selection that sufficient accuracy and precision may be achieved.
Features with inclination	Roads, rivers, drains, valves, drips, etc.
Diameter and wall thickness	Nominal pipe diameter and wall thickness.
Pressure	Typical minimum and maximum operating pressures.
Flow rate	Flow rates- minimum and maximum flow rates at minimum and maximum operating pressures for all inlets and outlets. Significant periods of low/no flow.
Temperature	For example, ambient soil temperature up to 54^{o}C (130^{o}F) at compressor discharge (2) unless a special environment exists (e.g., river crossing, aerial pipeline)
Water Vapor	Information about water vapor dew point.
Inputs/outputs	Must identify all locations of current and historic inputs and outputs to the pipeline.
Corrosion inhibitor	Information about injection, chemical type, and dose.
Upsets	Frequency, nature of upset (intermittent or chronic,) volume if known, and nature of liquid.
Type of dehydration	Is dehydration carried out using glycols (yes/no)?
Hydrostatic test information	Past pressure of water, hydrostatic test water quality data.

Table 4.6: (Continued) Essential Data for Use of DG-ICDA

Repair/ maintenance data	Presence of solids, anomalies; pipe section repair and replacement; prior inspections; NDE data. Any cleaning pig locations, frequencies, and dates. Analytical data of all removed sludge, liquids when cleaning pigs were employed or from liquid separators, hydrators, etc. and the analysis performed to determine the chemical properties corrosivity, including the presence of bacteria, of the removed products.
Leaks/failures	Locations and nature of the leaks/failures
Gas quality	Gas and liquid analyses, and any bacteria testing results for the pipeline and on shipper and delivery laterals. Relationship of gas analyses to pipe location.
Corrosion monitoring	Corrosion monitoring data including type of monitoring [e.g., coupons, electric resistance (ER)/ linear polarization resistance (LPR) probes,] dates and relationship of monitoring to pipe location, corrosion rate recorded/ calculated, and accuracy of data (e.g., NACE Publication 3T199: "Techniques for Monitoring Corrosion and Related Parameters in Field Applications"). Any available non-destructive inspection results.
Flow coatings	Existence and location(s) of internal coatings
Other internal corrosion data	As defined by the pipeline operator
(1) U.S. Geological Survey; (2) Gas Technology Institute, Report GRI-020057	

To find out if the DG-ICDA process is applicable for a particular pipeline, or portion thereof, the following conditions must be met:

- The pipeline should normally not contain any liquids, including glycols.
- The pipeline service should not have been previously converted from a service for which DG-ICDA is not applicable, e.g., crude oil and products.
- The pipeline must not have an internal coating.
- There should be no historical indication of internal corrosion at the top of the pipe from wet gas, i.e., from condensing water.

- There should not be areas where the effects of pigging/cleaning could result in liquid collection which directly affects the distribution of internal corrosion in a way that is not predicted by DG-ICDA.

Also:

- Using corrosion inhibitors may preclude using DG-ICDA because non-homogeneities in the inhibitor can diminish the effectiveness of the procedure along the pipeline.
- Pipelines that contain accumulations of solids, sludge, biofilm/biomass, or scale should not be assessed using DG-ICDA unless the influence of those materials has been carefully evaluated relative to the validity of the DG-ICDA results.

Flow modeling calculations along a DG-ICDA region include determination of:

- ***The critical inclination angle***, based on pipe diameter, gas density, liquid density, gravitation, superficial gas velocity and compressibility of the gas.
- ***The inclination profile,*** based on determining the variation in inclination angle () along the pipeline within each region. The inclination angle for any particular pipe span is calculated as:

$$= \arcsin \{(\text{elevation}) / (\text{distance})\}$$

The first upstream pipe inclination greater than the largest critical inclination angle would most likely be a site with liquid holdup; direct inspection through bellhole excavations are required as well as inspections to determine and document pipe condition, including internal corrosion deterioration.

Document the procedures used to determine the critical inclination angle and the inclination profile, the assumptions made, the method used to determine the uncertainty of the inclination profile, and the impact of this uncertainty.

Use the results of the flow modeling in conjunction with other pipe attributes and conditions to select specific sites for further internal corrosion excavation and inspections. These include:

- Road crossings, rivers and drainage ditches

- Sections where there has been bidirectional flow through the pipeline, designating separate DG-ICDA regions for each direction
- Short elevation change at a road crossings or other pipe features, where water commonly accumulates on the short uphill segment
- A long upslope such as a pipeline that climbs a hill or mountain, where the extent of liquid holdup may be difficult to determine and can occur over a longer area
- Drips or other water accumulation facilities whose corrosive environments are typically more severe than actual pipelines

After excavating the pipeline at the areas determined from the above analyses, suitable non-destructive testing procedures should be used to quantify the extent of internal corrosion. Criteria used to determine the presence of significant internal corrosion and the required number of detailed examinations include:

- Wall thickness that measures less than minimum specified nominal
- Results of a pipeline-specific analysis
- Other criteria, provided they are accompanied by technical justification

When DG-ICDA determines that locations most susceptible to corrosion due to water accumulation are free from metal loss, the integrity of a large portion of pipeline mileage can be relied on. This frees resources for pipelines where corrosion is calculated to be more likely. When the examination process identifies the existence of extensive severe internal corrosion, the operator must return to the DG-ICDA pre-assessment to determine if it is applicable.

4.1.5 NACE International SP0204 – Stress Corrosion Cracking Direct Assessment Methodology (SCCDA)

NACE SP0204 presents a SCCDA methodology for buried steel onshore natural gas, crude oil, and refined-product pipelines that are in production, transmission, or distribution service. As reviewed in Section 1 of NACE SP0204, SCCDA is applicable to both forms of external stress corrosion cracking (SCC), i.e., near-neutral-pH SCC and high-pH SCC. As with ECDA and ICDA, SCCDA is a continuous improvement process. SCCDA is a complement to other inspection methods, i.e., in-line inspection and hydrostatic tests. It is not necessarily an alternative or replacement for these methods.

NACE SP0204 addresses:

- The relationship between SCCDA and SCC integrity management
- The four-step SCCDA process: pre-assessment, indirect inspections, direct examination, and post-assessment
- Factors that can influence SCC, including a comprehensive listing with their relative significance and data interpretation and use
- Visual and physical inspection procedures, including pipe surface preparation
- Electrolyte sample collection and corrosivity test measurements
- Corrosion product sample collection and analysis
- Advantages and disadvantages of various magnetic particle inspection (MPI) techniques for detecting SCC
- Crack documentation and evaluation, including determination of maximum crack length, the effect of interlinking and interacting cracks, and presence of "significant" cracking
- In-situ metallography and ultrasonic tests
- Determining the need for and type of SCC mitigation through the post assessment process
- Periodic reassessment and recordkeeping

4.1.5.1 Pre-Assessment — Susceptibility to Stress Corrosion Cracking

Section 3 of NACE SP0204 presents pre-assessment guidelines to determine a pipeline's susceptibility to stress corrosion cracking. According to Part A of ASME B31.8S, gas pipeline segments considered to be susceptible to high-pH SCC must meet all of the following factors:

- Operating stress exceeds 60% SMYS
- Operating temperature has historically exceeded 38°C (100°F)
- Segment length is less than or equal to 32 kilometers (20 miles) downstream from a compressor station
- Pipeline age is greater than or equal to ten years
- External coating is other than fusion bonded epoxy

While ASME B31.8S addresses gas pipelines, the above factors are also appropriate and can generally be used to determine SCC susceptibility for liquid petroleum pipelines. For liquid petroleum pipelines, the distance downstream from a pump station is one influencing factor to select potential susceptible pipe segments. While Part A of ASME B31.8S does not currently address near-neutral pH SCC, the same factors listed above can be used, with the exclusion of temperature.

Table 4.7 has been reprinted from NACE SP0204 and summarizes various considerations and their relevance to SCC. These factors are ranked according to their relevance when selecting direct inspection sites to determine the extent of SCC.

Table 4.7: Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
PIPE-RELATED			
Grade	No known correlation with SCC susceptibility	Background data needed to calculate stress as percent of SMYS	C
Diameter	No known correlation with SCC susceptibility	Background data needed to calculate stress from internal pressure	C

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Wall thickness	No known correlation with SCC susceptibility	Impacts critical defect size and remaining life predictions; needed to calculate stress from internal pressure	C
Year manufactured	No known correlation with SCC susceptibility	Older pipe materials typically have lower toughness levels, reducing critical defect size and remaining life predictions	C
Pipe manufacturer	Near-neutral-pH SCC has been found preferentially in the HAZ of ERW pipe that was manufactured by Youngstown Sheet and Tube in the 1950s; reported to be statistically significant predictor for near-neutral-pH SCC in system model for one pipeline system	Important factor to consider for near-neutral-pH SCC	A
Seam type	Near-neutral-pH SCC has been found preferentially under tented tape coatings along DSA welds and in HAZs along some electric-resistance welds; no known correlation with high-pH SCC.	May be important factor to consider for near-neutral-pH SCC	B
Surface preparation	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high-pH SCC[6]	Important factor to consider for both high-pH and near-neutral pH SCC	A

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Shop coating type	To date, SCC has not been reported for pipe with undamaged fusion-bonded epoxy (FBE) coating or with extruded polyethylene coating	Important factor to consider for both high-pH and near-neutral pH SCC	A
Bare pipe	SCC has been observed on bare pipe in high-resistivity soils	May be important factor	B
Hard spots	There have been instances in which near-neutral-pH SCC has occurred preferentially in hard spots, which can be located by ILI that measures residual magnetism	May be important factor	B
CONSTRUCTION-RELATED			
Year	Impacts time over which coating degradation may occur and cracks may have been growing	Age of pipeline used in criteria for selection of susceptible segments in Part A3 of ASME B31.8S[1]	A
Route changes/ modifications		May be important for accurately locating each site	C
Route maps/ aerial photos		May be important for accurately locating each site	C
Construction practices	Backfill practices influence probability of coating damage during construction; time between pipe burial and installation of CP might be important	Early levels of CP might be important	B
Surface preparation for field coating	Mill scale promotes potential in critical range for high-pH SCC	May be discriminating factor	A

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Field coating type	High-pH SCC found under coal tar, asphalt, and tape; near-neutral-pH SCC most prevalent under tape but also found under asphalt; weather conditions during construction also may be important in affecting coating condition	Important factor to consider for near-neutral-pH SCC	A
Location of weights and anchors	Near-neutral-pH SCC has been found under buoyancy-control weights	Might be important, especially for near-neutral-pH SCC	B
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and isolating joints	No known relation to SCC. Just applicable to locating and characterizing sites	May be important for accurately locating and characterizing each site	C
Locations of casings	CP shielding and coating damage more likely within casings	May be important for accurately locating and characterizing each site	B
Locations of bends, including miter bends and wrinkle bends	Might indicate unusual residual stresses	Residual stress may be an important factor	B
Location of dents	Might indicate unusual residual stresses	Residual stress may be an important factor	B

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
SOIL/ENVIRONMENTAL			
Soil characteristics/types (Refer to Appendix A of NACE SP0204)	No known correlation between soil type and high-pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings; some success has been experienced in correlating near-neutral-pH SCC with specific soil types	Might be important, especially for near-neutral-pH SCC	B
Drainage	Has been correlated with both high-pH and near-neutral-pH SCC	Might be important parameter	B
Topography	Has been correlated with both high-pH and near-neutral-pH SCC, possibly related to effect on drainage; also, circumferential near-neutral-pH SCC has been observed on slopes where soil movement has occurred	Might be important parameter	B
Land use (current/past)	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings	Might be important parameter	B
Groundwater	Groundwater conductivity affects the throwing power of CP systems	Might be important parameter	B
Locating of river crossings	Affects soil moisture/drainage	Might be important parameter	B

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	Adequate CP can prevent SCC if it reaches under disbonded coatings	Important parameter	B
CP evaluation criteria	Adequate CP can prevent SCC if it reaches under disbonded coatings	Background information	C
CP maintenance history	Adequate CP can prevent SCC if it reaches under disbonded coatings	Background information	C
Years without CP applied	For high-pH SCC, absence of CP might allow harmful oxides to form on pipe surface; for near-neutral-pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed	Important parameter	B
CIS and test station information	Although high-pH SCC occurs in a narrow range of potentials (typically between -575 and -825 mV vs. copper/copper sulfate [$Cu/CuSO_4$] depending on the temperature and solution composition), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential at the pipe surface can be less negative than the aboveground measurements because of shielding by disbonded coatings; nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past	Important factor to consider for both high-pH and near-neutral pH SCC	B

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Coating-fault survey information	Because SCC requires coating faults, indications of coating condition might help locate probable areas	Important background information	B
Coating system and condition	The coating system (coating type, surface condition, etc.) is an important factor in determining SCC susceptibility and the type of SCC that occurs; because SCC requires coating faults, indications of coating condition might help locate probable areas	Important background information	A
OPERATIONAL DATA			
Pipe coating temperature	Elevated temperatures have strong accelerating effect on high-pH SCC; for near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration	Important, especially for high-pH SCC	A
Operating stress levels and fluctuations	Stress must be above a certain threshold for SCC to occur; fluctuating stresses can significantly reduce the threshold stress	Impacts SCC initiation, critical flaw size, and remaining life predictions	A
Leak/rupture history (SCC)	There is a high probability of finding more SCC in the vicinity of previously discovered SCC	Important	A
Direct inspection and repair history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC	Important	A

Table 4.7: (Continued) Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Hydrostatic retest history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC	Important	A
ILI data from crack-detecting pig	There is a high probability of finding more SCC in the vicinity of previously discovered SCC	Important	A
ILI data from metal-loss pig	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC — especially near-neutral-pH SCC — has been observed	May be important	A

(1) ASME International (ASME), Three Park Avenue, New York, NY 10016-5990; (6) Pipeline Research Council International, Inc. (PRCI), 1401 Wilson Boulevard, Suite 1101, Arlington, VA 22209

The Relative Importance of Each Data Element (indicated in the last column) is:

A: Usually important for prioritizing sites

B: May be important for prioritizing sites in some cases

C: Not relevant to prioritizing, but may be useful for record keeping

4.1.5.2 Indirect Inspections

Similar to ECDA, indirect inspections (Section 4 of NACE SP0204) are used as a precursor to determine locations for direct examinations. Procedures include:

- Close interval potential surveys
- Coating fault surveys

- Geological surveys and characterization
- In-line geometry inspection tools to determine locations of features such as dents and bends which have been associated with SCC
- Magnetic flux leakage in-line inspection tools to determine locations of coating disbondment and corrosion, which have been associated with SCC

4.1.5.3 Direct Examinations

Direct examination procedures covered in Section 5 of NACE SP0204 are based on the pre-assessment data and, if applicable, the indirect inspections. If SCC is detected, the direct examinations are used to assess and document the presence, extent, type and severity of SCC. Data can also be collected to be used during post-assessment to develop or refine a predictive model.

Table 4.8: Data Collected at a Dig Site in an SCCDA Program and Relative Importance

Data Element	When Collected	Use and Interpretation of Results	Ranking
Pipe-to-soil Potential	Prior to coating removal	Useful for comparison with ground surface pipe-to-soil potential measurements	D
Soil resistivity	Prior to coating removal	Related to soil corrosiveness and soluble cation concentration of soil; useful for comparison with results of soil and groundwater analyses	C
Soil samples	Prior to coating removal	Useful in confirming terrain conditions; soil analysis results can be trended in predictive model	B
Groundwater samples	Prior to coating removal	Chemistry results can be trended in predictive model	B
Coating system	Prior to coating removal	Required element; used for field site verification and in predictive model development	A

Table 4.8: (Continued) Data Collected at a Dig Site in an SCCDA Program and Relative Importance

Coating condition	Prior to coating removal	Can be related to extent of SCC found	C
Measure of coating disbondment	Prior to coating removal	Locations of disbondment can be related to presence of cracking and other measured data	C
Electrolyte	Prior to coating removal	Useful in establishing type of cracking; can be related to groundwater chemistry	C
Photograph of dig site	Prior to coating removal	Useful in confirming terrain conditions, coating system, and coating condition	D
Data for other integrity analyses	Before and after coating removal	Data for other analyses (e.g., dent measurements) may be related to occurrence of SCC	C, D
Deposit description and photograph	After coating removal	Useful in establishing type of cracking	C
Deposit analysis	After coating removal	Useful in establishing type of cracking	C
Identification and measurement of corrosion defects	After coating removal	Used for integrity assessment of corrosion defects; also used in establishing type of SCC, if present	A, D
Photograph of corrosion defects	After coating removal	Used in integrity assessments	D
Identify weld seam type	After coating removal	Required element; used in field site verification	A
MPI	After coating removal	Required element for SCCDA; establishes whether SCC is present	A
Location and size of each cluster	After coating removal	Required element for SCCDA; used to establish correlation of location with other parameters measured	A

Table 4.8: (Continued) Data Collected at a Dig Site in an SCCDA Program and Relative Importance

Crack length and depth measurements	After coating removal	Required element for SCCDA; used to establish significance of cracking and determine whether there is an immediate integrity concern	A
In situ metallography	After coating removal	Used to establish type of SCC	B
Photograph clusters	After coating removal	Required element for SCCDA; used to confirm crack measurements	A
Wall thickness measurements	After coating removal	Required element; used in integrity assessments and field site verification	A, D
Measure pipe diameter	After coating removal	Required element; used in integrity assessments and field site verification	A, D

A: Required element for SCCDA

B: Optional (likely useful in SCCDA model development)

C: Optional (might be useful in SCCDA model development)

D: Useful background information or information used in other analyses

Included in the direct examination protocol are magnetic particle inspection procedures to detect possible cracking. When crack clusters are determined, it is essential to document and evaluate the cracking for safety and pipeline integrity. This includes extent (e.g., axial length and width of colony), presence of interlinking cracks, presence of interacting cracks, and cause of cracking (e.g., high-pH SCC and mechanical damage).

4.1.5.4 Post-Assessment and Recordkeeping

Post assessment (Section 6 of NACE SP0204) establishes the extent of SCC mitigation needed, defines the reassessment intervals and provides an analysis of the process.

Mitigation procedures are thoroughly detailed in Part A of ASME B31.8S and include, among others:

- Pipe repair
- Pipe replacement
- Hydrostatic testing
- Critical engineering assessment to determine extent of mitigation based on risk
- In-line inspection tools
- Coating repair or replacement

Factors used for determining reassessment intervals include:

- Extent and severity of SCC detected
- Estimating the propagation rate of detected crack clusters and the remaining life of the pipe containing the clusters
- The total length of the pipeline and the length of the segments containing SCC
- The potential consequences of a failure within a given segment

Assessing the effectiveness of SCCDA is critical to the validity of the data collected and its use to determine mitigation measures and reassessment intervals. Validation procedures include but are not limited to:

- Comparison of data from selected dig sites with data from control digs
- Comparison of SCCDA results with results from in-line crack detection tools
- Statistical analysis of the SCCDA data to identify statistically significant factors associated with the occurrence or severity of cracking
- Successive applications of SCCDA to a pipeline segment
- Assessment of SCC predictive models relative to their reliability in predicting SCC locations and severity

As you collect data over time, it is essential to have feedback from this information continually to improve the SCCDA process; clear and concise recordkeeping is critical to the success of all phases: pre-assessment, indirect inspections, direct examination, and post-assessment.

4.1.6 NACE International SP0102 – In-Line Inspection of Pipelines

As summarized in Section 1 of NACE SP0102, this practice pertains to in-line inspection (ILI) of carbon steel pipeline systems used to transport natural gas, hazardous liquids including anhydrous ammonia, carbon dioxide, water (including brine), liquefied petroleum gases (LPGs), and other services that are not detrimental to the function and stability of ILI tools. The standard is primarily applicable to "free swimming" ILI tools but not tethered or remotely controlled inspection devices.

NACE SP0102 addresses:

- Tool selection, including detection accuracy, detection sensitivity, classification capability, sizing accuracy, location accuracy, and defect assessment algorithm
- Operational issues, including ILI tool launchers, receivers, and other mechanical characteristics; fluid characteristics, tool characteristics and compatibility
- Types of ILI tools and inspection purposes
- Contracting considerations, including responsibilities, liability, survey acceptance criteria, and reporting
- ILI tool tracking, including surveying, benchmarking, transmitters, and milestones
- Subsea surveys
- Contingency planning
- Inclusion of ILI provisions in new pipeline design and construction, including a baseline survey shortly after operations commence

- Data analysis methodologies including software, algorithms, feature listing, and anomaly locations
- Verification excavation/inspections and correlation with ILI data
- Data management, including incorporation into an overall pipeline integrity management plan
- Corrosion feature growth rates
- Sample questionnaire for planning an ILI evaluation

As reviewed in Section 3 of NACE SP0102, ILI tool selection is determined based on the specific condition assessment needs. Table 2.8 in Chapter 2 identifies typical ILI tools and their inspection purpose. Selection factors common to all tools include: accuracy and detection capability, detection sensitivity, anomaly classification capability, and anomaly location accuracy.

Operational issues that impact ILI feasibility and reliability include: pipe characteristics such as length and joint type; launchers and receivers; pipe cleanliness; product speed and flow; extreme temperatures (hot and cold); and characteristics and aggressiveness of the fluid.

When you design a new pipeline, sufficient provisions for ILI should be included. Details are addressed in Section 7 of NACE SP0102.

Sections 8 and 9 of NACE SP0102 review ILI data reporting. ILI inspection reports provided by vendors should follow an agreed upon format consistent with industry standards and include the following typical provisions:

- Detection, location, classification and sizing of anomalies
- Probability of detection of a given feature, defined as the statistical probability of detecting that type of feature
- Nearby features and benchmarks

4.1.7 CSA Standard Z662 – Oil and Gas Pipelines

CSA Z662 is a comprehensive standard relating to many aspects of oil and gas pipeline systems; major sections of the standard include:

- Design
- Materials
- Installation
- Joining
- Pressure testing
- Corrosion control
- Operating, maintenance, and upgrading
- Offshore steel pipelines
- Gas distribution systems
- Plastic pipelines
- Oilfield steam distribution pipelines
- Aluminum piping

While pipeline integrity and risk assessment are not a specific part of CSA Z662, many aspects of this document are applicable to these subjects; particularly some of the condition assessment procedures, corrosion control practices, and remediation measures.

Appendix B in CSA Z662, "Guidelines for Risk Assessment of Pipelines," is for information purposes, i.e., it is not part of the standard. Appendix B outlines:

- The scope of the risk assessment process, including hazard identification, frequency analysis, consequence analysis, and risk estimation, as well as risk significance and control options.
- Risk assessment concepts, including a structured process to identify both the extent and likelihood of consequences associated with hazards.

- Hazard identification, including:
    - Comparative methods such as checklists, hazard indices, and historical failure data
    - Structural methods such as hazard and operability studies (HAZOP) and failure modes and effects analysis (FMEA)
    - Logical pathways to translate different release or initiating events into possible outcomes, including event tree analysis and fault tree analysis
- Frequency analysis approaches to determine failure likelihood, including:
    - Analysis of historical operational and incident data
    - Fault and event tree analysis
    - Mathematical modeling
    - Experience and judgment based on known conditions
- Consequence analysis to predict the magnitude of adverse effects resulting from such events as releases of toxic or flammable fluids and disruption of pipeline throughput
- Risk evaluation and determination of risk significance, including the potential frequency of occurrence of the hazardous event and the cost savings associated with any incremental reduction in estimated risk level
- Options analysis to evaluate the effectiveness of available risk reduction measures

A sample risk matrix from Appendix B of CSA Z662 is reprinted as Figure 4.5.

The risk assessment process set forth is CSA Z662 (Appendix B, Section B.6) culminates in a risk assessment report. The report content should be dependent on the objectives and scope of the assessment and typically includes:

- Objectives and scope
- System description
- Risk analysis methodology
- Limitations and assumptions
- Hazard identification results

- Frequency analysis results, including assumptions
- Consequence analysis results, including assumptions
- Risk estimation results
- Sensitivity and uncertainty analysis
- Discussion of results, including analysis problems
- Conclusions and recommendations
- References, including sources to support any modeling or other analytical techniques used
- Names and qualifications of personnel who participated in the risk assessment

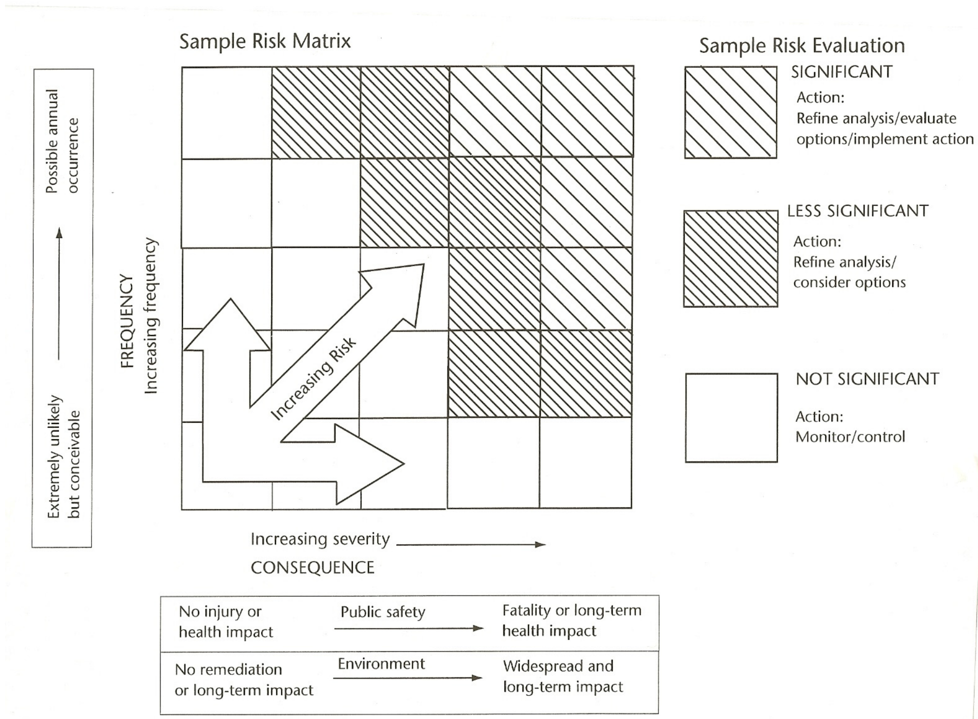


Figure 4.5 Example of Risk Matrix Application to Risk Estimation and Evaluation

Chapter 5: Data Collection, Verification and Integration

After completing this chapter, students should be able to:

- Perform data collection.
- Identify types of data to collect for risk assessment.
- Perform data validation.
- Perform data integration.

5.1 Introduction

Developing and implementing a tightly structured pipeline integrity management program is now a regulatory requirement for most hazardous liquids and natural gas transmission pipeline operators in the United States. One of the basic requirements of an integrity management program is integration of information pertinent to pipeline integrity. Without good data integration, effective information analysis is impossible. Without effective information analysis, pipeline integrity issues cannot be identified or resolved. This chapter addresses the elements of an integrity program: data integration, types of integrity data, expected results, data integration, methods of integration, and qualifications of personnel who will conduct data integration.

In recent years federal and state laws and regulations have been enacted in the United States that require hazardous liquids and natural gas transmission pipeline operators to implement tightly structured pipeline integrity management programs. These pipeline integrity management programs are mandated to reduce risks for people, property and the environment that are close to pipelines. The regulations are commonly referred to as “high consequence area” or HCA regulations.

One of the major elements of an integrity management program required by the regulations is "an analysis that integrates all available information about the integrity of the entire pipeline, its relevance to the particular HCA segment, and the consequences of a failure or accident." Integrity information is any information that is pertinent to any pipeline integrity issue. Data integration is the correlation of integrity information in a manner that facilitates identification of integrity issues. The HCA regulations are specific about the types of integrity data and require that data for entire pipelines be collected and integrated, not just those segments identified as HCA.

The HCA regulations for hazardous liquids and natural gas transmission pipeline operators are similar in many respects, but have significant differences. Most notably, hazardous liquids pipeline operators are allowed to use in-line inspection and pressure testing to assess pipeline condition. Gas transmission pipeline operators are allowed to use these two assessment techniques plus Direct Assessment. (It is anticipated that hazardous liquids regulations will be amended to allow Direct Assessment at some time in the near future.)

Both groups of pipeline operators are also allowed to use alternate technologies if it can be demonstrated they provide equivalent information to that derived from in-line inspection, pressure testing, and direct assessment. For simplicity, this chapter merges requirements of the hazardous liquids and gas transmission regulations, since many of the requirements are equivalent.

5.1.1 Program Requirements and Elements

Whether a pipeline integrity management program is for a hazardous liquids or gas transmission pipeline, the program is required to contain specific minimum elements and fulfill specific minimum requirements:

- Written integrity management program
- Risk factors assignments
- HCA segments identification
- Risk determinations
- Baseline assessment plan and schedule
- Defect identification and repair

- Baseline assessments
- Other remedial and preventive actions
- Information (data) integration
- Continual program improvement
- Information (data) analysis
- Continual integrity assessment

Data integration is identified by HCA regulations as one of the fundamentals of a pipeline integrity program. Data integration must take place before risk determinations or remedial/preventive actions can be taken. Data integration does not just occur one time in an integrity program, it should be a continuing process.

5.2 Data Collection

The objective of gathering, integrating and analyzing data is to determine the overall condition of a pipeline system in accordance with the information analysis requirements of 49 CFR 195.452 Pipeline Integrity Management in High Consequence Areas (HCA).

Regulations require all pipeline operators to have a program in place to collect data pertinent to an integrity risk assessment. According to the American Society of Mechanical Engineers (ASME) there are two types of industry accepted integrity management programs available. Those two methods are the Prescriptive method and the Performance-Based method. The Prescriptive method (Non-mandatory Appendix A of ASME B31.8S) is the method of choice when data is insufficient or of poor quality. The Performance-Based method calls for broad pipeline and facility knowledge; areas of interest include, but are not limited to, the current pipeline integrity level, the current pipeline protection level, historical data, location of all High Consequence Areas (HCAs) and Unusually Sensitive Areas (USA). Other types of data can be obtained from third party surveyors and pipeline facility and equipment manufacturer's specifications. During the initial stage of data collection, the units and level of resolution of data must be decided upon. All pipeline integrity related data for the facility being evaluated must be incorporated. The encompassing focus should be to get information that will result in the highest resolution data integration to accurately and completely assess the pipeline's condition.

ASME B 31.8S "Managing System Integrity for Gas Pipelines" Section 4.4 titled: "Data Collection, Review and Analysis," states that "A plan for collecting, reviewing and analyzing the data shall be created and in place from the conception of the data collection effort. These processes are needed to verify the quality and consistency of the data. Records shall be maintained throughout the process that identify where, and how any unsubstantiated data is used in the risk assessment process so its potential impact on the variability and accuracy of assessment results can be considered." According to ASME B31.8S, another data collection consideration is if the age of the data invalidates its applicability to the threat. Data about time-dependent threats such as corrosion or Stress Corrosion Cracking (SCC) may not be relevant if it was collected many years before the integrity management program was developed. Stable and time independent threats do not have implied time dependence so earlier data is applicable.

Data collection information related to pipeline integrity, integrity deficiencies and the consequences of failures typically fall into five distinct groups of information: (1) current integrity of pipeline, (2) current level of protection for the pipeline, (3) historical data, (4) HCA data, and (5) USA data. Each of these information categories will be individually discussed in detail.

Industry and regulatory codes and practices applicable to the data collection and integration process include:

- U.S. Code of Federal Regulations (CFR) Title 49. CFR 195 U.S. Department of Transportation. "Minimum Federal Safety Standards for the Transportation of Hazardous Liquids by Pipeline."
- U.S. Code of Federal Regulations (CFR) Title 49. CFR 192 U.S. Department of Transportation. "Minimum Federal Safety Standards for the Transportation of Natural and other Gas by Pipeline."
- ASME B31.4. "Pipeline Transportation for Liquid Hydrocarbons and other Liquids." ASME, 2006.
- ASME B31.3. "Code for Process Piping." ASME, 2006.
- ASME B31.8S. "Code for Managing System Integrity of Gas Pipelines." ASME, 2004.

- API Standard 1160. "Managing System Integrity for Hazardous Liquid Pipelines." API, 2001.

5.2.1 Current Integrity of Pipeline

All available data should be used to assess pipeline integrity. The following data and reports are particularly useful to define the pipeline system and determine its overall condition:

- Regulatory maps and records
- In-line electronic inspection results, repair plans and repair reports
- Cathodic protection survey reports
- Rectifier output test and inspection reports
- Pipeline DOT required maintenance records
- Pipeline field inspection reports and records
- Third Party activity investigation reports
- Casing inspection and test reports
- Foreign pipeline crossing reports
- Pressure rest reports

This data is used in the risk assessment process in accordance with the operators' written integrity management program and procedures. An accepted method to analyze the data is for a team of personnel, knowledgeable about the system, its operation and maintenance history, and familiar with its maintenance, operational and integrity procedures, to review it.

5.2.2 Current Level of Protection

Information about the current level of pipeline protection can be extracted from any of the following records:

- **Pipe-to-Soil Potential Records**

  Pipeline operators have a regulatory obligation to conduct pipe-to-soil surveys once a year with intervals not to exceed 15 months. Records to document this survey must be maintained by the operator for as long as the pipeline remains in service.

Electrical potential is a negative electrical voltage applied to a pipeline to provide cathodic protection. The potential is usually applied to the pipeline by a rectifier and/or anodes. Potential readings from a copper-copper sulfate electrode are taken at regular intervals along the pipeline at test leads or points where direct electrical contact can be made with the pipeline. If the potential across a section of pipeline is above (or less negative than) the established level of protection needed, then the cathodic protection may be deficient and measures will be required to identify and rectify the source of the problem. On the other hand, if the potential of a copper-copper sulfate electrode across a section of pipeline is above certain levels, the coating on the pipeline may disbond. Coating disbondment eliminates the coating's electrical insulating qualities and can shield the pipe from the cathodic current. Pipe-to-soil survey records are relevant for all the reasons mentioned above and are indicative of the overall condition of the pipeline cathodic protection system.

- **Rectifier Survey Records**

Pipeline operators have a regulatory obligation to maintain current records to document any tests and/or inspections of rectifiers. The normal regulatory frequency to check rectifiers is six times a year but with intervals not to exceed 2.5 months. Records that document rectifier inspections must be maintained by the operator for five years.

The power supply for a cathodic protection system is normally provided by rectifiers and anodes distributed as required along the pipeline. Output readings for the rectifiers indicate the overall condition of the cathodic protection system.

- **Daily Operating Records**

Pipeline operators have a regulatory obligation to maintain daily operation records for three years.

Daily operating records include the discharge pressure at each pump station, a record of any abnormal or emergency operation, daily operating records, which can include nonregulatory data such as Supervisory Control and Data Acquisition (SCADA) reports comprised of dynamic leak detection line balance calculations, periodic alarm status reports, or other useful system specific data. Daily operating records are useful to identify operating conditions outside design parameters.

- **Line Flyer and Encroachment Reports**

  Pipeline operators have a regulatory obligation to inspect and document the surface conditions along the pipeline at least 26 times per year at intervals not exceeding three weeks. Records to document the ROW inspections must be maintained for two years.

  Most pipeline operators utilize line flyers to complete this inspection. Line flyer reports are particularly useful to document current and potential third party encroachments on the pipeline ROW.

- **Pressure Test Records**

  Current pipeline regulations require that all new hazardous liquid or gas pipelines be pressure tested before they are placed in service. Pipeline operators have a regulatory obligation to maintain records to document the most recent pressure tests.

  Pressure tests are an accepted integrity assessment method. Hydrostatic pressure testing, where clean water is used as the test medium, is the most common pressure test method. Pressure tests are, in many cases, the determinant used to establish the maximum allowable operating pressure for a pipeline.

- **In-Line Inspection Records**

  An In-Line Inspection (ILI) with an internal smart pig, capable of recording and identifying the location of defects in the pipe, is an accepted hazardous liquid or gas pipeline integrity assessment method. An ILI tool electronically records data as it traverses the pipeline propelled by the product that is transported.

  The primary function of an ILI is to gather data about the current condition of the pipeline and the location of previously unknown features. ILI tools are capable of identifying, locating, and measuring defects such as corrosion pitting, mill defects, cracks, and dents.

- **Bell Hole Inspection Records**

  A bell hole inspection is a field inspection of a buried pipeline made any time it is necessary to excavate it. Current pipeline regulations require operators to document bell hole inspections when pipeline regulatory inspections and/or repairs are made. In many cases this documentation is maintained for the life of the system.

- **External Corrosion Direct Assessment Records**

  An External Corrosion Direct Assessment (ECDA) is an accepted hazardous liquid or gas pipeline integrity assessment method. It is a structured process used to access the overall condition of a pipeline system by identifying and addressing external corrosion. The ECDA process has four steps: (1) Pre-Assessment, (2) Indirect Inspection, (3) Direct Examination, and (4) Post Assessment.

  In Pre-Assessment historic and current system data are collected to determine whether ECDA is feasible for the system, the ECDA regions are defined, and appropriate indirect inspection tools are selected. This step requires a review of all available historic data.

  Indirect Inspection is an above ground inspection to identify and define the severity of coating faults, anomalies, and/or areas where corrosion may have already occurred or be occurring.

  Direct Inspection analyzes indirect inspection data to select sites for excavation and pipe surface evaluation. The direct examination data is combined with prior data to: identify and assess the impact of external corrosion, evaluate pipeline coating performance, corrosion defect repairs, and mitigate corrosion protection faults.

  Post Assessment analyzes the data collected from the previous three steps to assess the effectiveness of the ECDA process and to determine reassessment intervals.

  The ECDA process utilizes a minimum of two of the following indirect inspection tools: (1) Close Interval Surveys (CIS), (2) AC Current Attenuation surveys, (3) DC and AC Voltage

Gradient surveys, (4) Pearson Surveys, and (5) Cell to Cell Surveys.

Once the above factors have been determined, data from each step can then be incorporated into the operator's risk assessment program.

5.2.3 Historical Data

Historical pipeline system data is part of data integration and can be separated into three primary categories: (1) construction, (2) operation, and (3) maintenance. Specifics of each of these categories are:

Construction

- Pipe material specifications
- External coating on buried pipe
- Pipe manufacturing information
- Joint coating systems
- Pipeline design information
- Internal coatings
- Pipe type (ERW, seamless, etc.)
- Atmospheric pipe coatings
- Diameter
- Construction techniques
- Grade
- Padding and backfill materials
- Specified minimum yield strength
- Depth of cover
- Wall thickness
- Electrical isolation devices
- Appurtenances (valves, etc.)
- Construction inspection
- Civil survey and mapping
- Hydrostatic testing and drying
- Date of construction
- Terrain and soil types
- Pipe transportation and handling

- Geological hazards

Operation

- Product transported
- Chemical treatment history
- Product quality
- One Call Program participation
- Maximum operating pressure
- Electrical interference (DC and AC)
- Operating stress level
- Surveillance and patrols
- Hydraulic gradients
- Security (fencing, locks, etc.)
- Leak surveys and history
- Emergency response preparedness
- Cathodic protection surveys and history
- Encroachment control
- Internal corrosion surveys and history
- Third Party notices and education
- Product flow regime
- Public notices and education
- Cleaning pig history
- Operator training and qualifications

Maintenance

- Hydrostatic testing
- Cased pipe remedial work
- In-line inspections
- Pipeline lowering and relocating
- External corrosion direct assessments
- Exposed pipe cover repair
- Internal corrosion direct assessments
- Coating repairs
- Stress corrosion cracking direct assessments
- Cathodic protection improvements

- Defect evaluations
- Markers and signs
- Pipe replacements and repairs
- Right-of-way mowing

Figure 5.1 displays some sources and alignment of data used for an integrity management program.

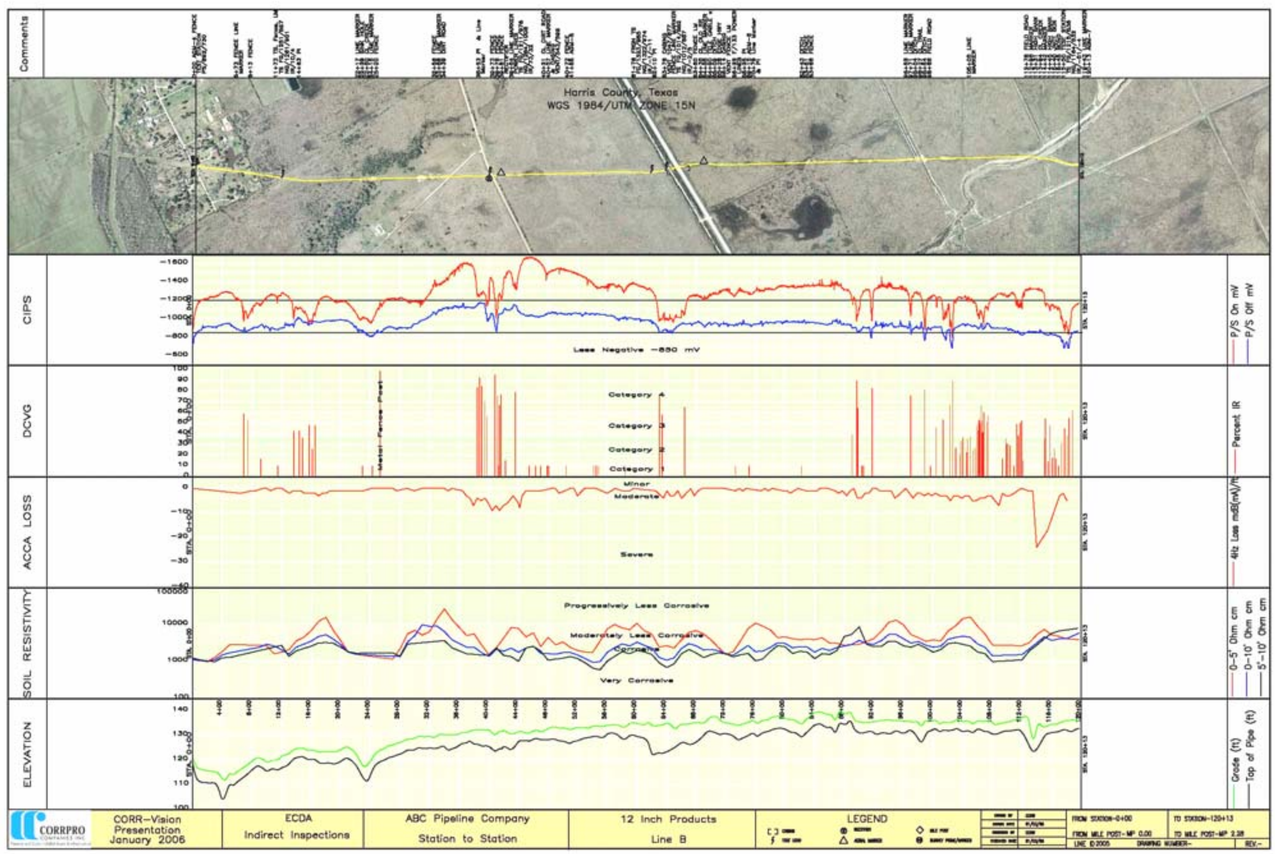


Figure 5.1 Combined Inline Inspection and External Corrosion Direct Assessment Chart

Sources of pipeline system information include, but are not limited to, construction specifications, pipe and pipeline device purchase orders, pipe and pipeline device manufacturing records, construction inspection reports, civil and global positioning (GPS) surveys, pipeline alignment sheets, hydrostatic test records, standard operating procedures, system control logs, product flow modeling and studies, population density and land use surveys, pipeline modification and repair records, corrosion control test and inspection records, product quality tests, and the entire spectrum of operations and maintenance reports generated while complying with all pipeline regulations or performing work in accordance with standard operating procedures implemented by pipeline operators.

5.2.4 HCA Data

The HCA regulations require that all information related to pipeline integrity, integrity deficiencies, and the consequences of failures be incorporated in the information analysis that is used to identify integrity deficiencies. Information for the entire pipeline, not just the HCA segments, must be incorporated, including:

- Location and attributes of HCAs
- Information critical to determine the potential for, and the prevention of, damage caused by excavation, including current and planned damage prevention activities, and present and planned development.
- Information gathered during integrity assessment activities required by the HCA regulations.
- Information gathered in conjunction with other inspections, tests, surveillance, and patrols required by other pipeline regulations.
- Information related to the impacts of failures in HCA segments.

5.2.5 Unusually Sensitive Area (USA) Data

49 CFR 195.6a defines a USA as "a drinking water or ecological resource area that is unusually sensitive to environmental damage from hazardous liquid pipeline release."

A USA drinking water resource is:

- "The water intake for a Community Water System (CWS) or a Nontransient Non-community Water System (NTNCWS) that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source."

- "The Source Water Protection area for a CWS or NTNCWS that obtains its water supply from a Class I or Class IIA aquifer and does not have an adequate alternative drinking water source."
- "The Sole source aquifer recharges area where the sole source aquifer is a karst aquifer in nature."

An USA ecological resource is:

- "An area containing a critically imperiled species of ecological community,
- A multi-species assemblage area,
- A migratory water bird concentration area, or
- An area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or an imperiled ecological community where the species or community is aquatic, aquatic dependent, or terrestrial with a limited range."

Since the preceding regulations are in the initial stages, the definition of USAs is being continuously redefined. Operator integrity management personnel should therefore periodically reference 49 CFR 195.6 for updates. USA regulations pertain to liquid transmission pipelines. Much like high consequence areas elsewhere, unusually sensitive areas require immediate attention when anomalous conditions occur. USA regulations require an operator to identify pipelines within them and gather information about the section for integrity assessment. This assessment should determine with precision the integrity of the pipeline and evaluate potential impact to the USA in the event of a hazardous liquid release. Because USAs are categorized as high consequence areas, much of the information gathered for risk assessments are the same for both hazardous liquids and gas.

Data collected should include: pipeline integrity data, integrity deficiencies, and consequences of failures. Depending on the results of the risk assessment and the proximity of the pipeline to the USAs, additional requirements such as added mitigation, prevention, monitoring, and response actions may be imposed on the operator to ensure the pipeline is in good condition. Data should also be gathered for any USA in the vicinity of the pipeline.

The data collected should in turn be integrated into the integrity management program for risk analysis and periodic monitoring. Sources to identify USAs near pipelines include: regional water districts, U.S. Geological Surveys, and state organizations that maintain databases of surface water intakes and groundwater wells for public water systems.

5.3 Data Validation

Data validation is vital to data integration. Data should never be integrated into any database, application, or integrity management plan without first being validated. Data validation affords us the opportunity to create visual continuity between data sets, permits correlation between historical hard copy data, and makes it easier to locate anomalous conditions. For example, a pipeline casing, whose history appears in two separate databases with each database referencing different survey stations for the same feature, or an in-line inspection whose approximate survey stations do not match the engineering survey station on the corresponding alignment sheet; each have data sets that do not correlate. In both cases an effort has to be made to correlate one to the other by some means of data validation.

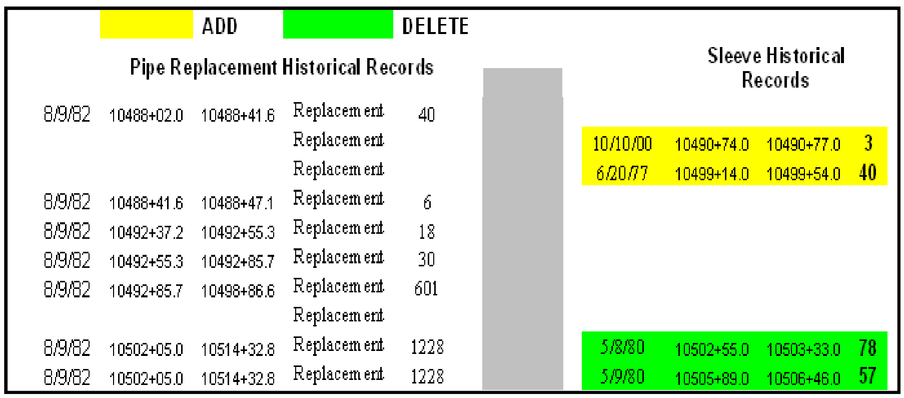
Another example is when an archived document is presented for data integration. Suppose the document mentions a sleeve that is not found in either a database or on an alignment sheet. What happened to this sleeve? Was it removed or was it never integrated into the integrity management application?

How would you validate the status of the sleeve? Follow the logical sequence below:

- Look for the year the sleeve was installed;
- Research any pipeline reroutes or repairs that may have occurred after the date of installation;
- If this sleeve was installed in 1980 but the section of pipe which had the sleeve was replaced in 1982 then this feature does not need to be integrated into the integrity management application;

- If it was a metallic sleeve, not composite, then check the in-line inspection to see if the magnetic flux tool captured the signature of the sleeve; then
- If the MFL tool captured the signature of the sleeve, it is probable that the sleeve is still present.

This type of validation is especially important because, unlike a pipeline valve, a sleeve is not an above ground feature so its existence can not be easily verified by visual observation (see Figure 5.2).



ADD DELETE

Pipe Replacement Historical Records					Sleeve Historical Records			
8/9/82	10488+02.0	10488+41.6	Replacement	40				
			Replacement		10/10/00	10490+74.0	10490+77.0	3
			Replacement		6/20/77	10499+14.0	10499+54.0	40
8/9/82	10488+41.6	10488+47.1	Replacement	6				
8/9/82	10492+37.2	10492+55.3	Replacement	18				
8/9/82	10492+55.3	10492+85.7	Replacement	30				
8/9/82	10492+85.7	10498+86.6	Replacement	601				
			Replacement					
8/9/82	10502+05.0	10514+32.8	Replacement	1228	5/8/80	10502+55.0	10503+33.0	78
8/9/82	10502+05.0	10514+32.8	Replacement	1228	5/9/80	10505+89.0	10506+46.0	57

Figure 5.2 Pipeline Replacement Historical Data vs. Sleeve/Full Sole Historical Data

When considering in-line inspection data for integration, the information should be congruent with the alignment sheets and other historical data. For example, in-line inspection data can be linked to data on an alignment sheet by using a "Rubber-banding Equation," an equation that performs linear error correction based on control points (known locations on pipeline alignment sheets) and the in-line inspection tool odometer count.

Rubber-banding Equation

$$Msx = Ms1 + \left[\frac{(Ox - O1) * (Ms2 - Ms1)}{(O2 - O1)} \right]$$

Where, Ms_x – Map Station – Unknown

Ms_1 – Map Station – Nearest Upstream Known Reference

Ms_2 – Map Station – Nearest Downstream Known Reference

O_1 – Odometer / Wheel Count nearest Upstream Known Reference

O_2 – Odometer/Wheel Count nearest Downstream Known Reference

O_x – Odometer / Wheel Count – Known Location

Map Station – Nearest Upstream Known Reference	Odometer	Approximate Survery Station based on Odometer	Event Description	Msx – Map Station – Unknown
			Launcher	
Ms_1	O_1		WT CHANGE	
			WELD	
356+78	0.00	O_x 0+00	Valve AGM 01 - 356+78	356+78
	0.56	O_x 0+01	WELD	357+57
	4.76	O_x 0+05	WELD	363+45
	6.28	O_x 0+06	WELD	365+57
	16.31	O_x 0+16	Tap	379+60
	16.44	O_x 0+16	WELD	379+78
	19.64	O_x 0+20	Tee	384+26
	22.72	O_x 0+23	Metal in Close Prox	388+57
	23.00	O_x 0+23	WELD	388+95
Ms_2	O_2 25.53	O_x 0+26	Clamp	392+50
	26.48	0+26	WELD	393+82
412+50	39.83	0+40	Equation:412+50 BK = 409+69 AH	412+50
409+69	39.83	0+40	Equation:412+50 BK = 409+69 AH	409+69

Figure 5.3 Rubber-banding Equation Applied

In Figure 5.3 the rubber-banding equation is applied between the first AGM location along the in-line inspection and the nearest downstream reference point or known location, which in this case happens to be the Back portion of an equation.

Map Station – Nearest Upstream Known Reference	Odometer	Approximate Survery Station based on Odometer	Event Description	Msx – Map Station – Unknown
			Launcher	
			WT CHANGE	
			WELD	
356+78	0.00	0+00	Valve AGM 01 - 356+78	356+78
	0.56	0+01	WELD	357+57
	4.76	0+05	WELD	363+45
	6.28	0+06	WELD	365+57
	16.31	0+16	Tap	379+60
	16.44	0+16	WELD	379+78
	19.64	0+20	Tee	384+26
	22.72	0+23	Metal in Close Prox	388+57
	23.00	0+23	WELD	388+95
	25.53	0+26	Clamp	392+50
Ms_1	O_1 26.48	0+26	WELD	393+82
412+50	39.83	0+40	Equation:412+50 BK = 409+69 AH	412+50
409+69	39.83	O_x 0+40	Equation:412+50 BK = 409+69 AH	409+69
	39.91	O_x 0+40	WT CHANGE	409+80
	39.92	O_x 0+40	WELD	409+82
	58.45	O_x 0+58	Metal Loss EXTERNAL	435+78
	63.03	O_x 0+63	WT CHANGE	442+21
	63.13	O_x 0+63	WELD	442+35
	65.02	O_x 0+65	Stopple Fitting	445+00
	65.99	O_x 0+66	Clamp	446+35
	66.84	O_x 0+67	WT CHANGE	447+54
	66.90	O_x 0+67	WELD	447+64
	106.66	O_x 1+07	WELD	503+36
	123.37	O_x 1+23	WELD	526+80
	172.07	O_x 1+72	WELD	595+06
	195.33	O_x 1+95	Metal in Close Prox	627+66
	222.15	O_x 2+22	WELD	665+26
	275.80	O_x 2+76	WELD	740+48
	276.73	O_x 2+77	Metal Loss EXTERNAL	741+78
	279.80	O_x 2+80	Metal Loss EXTERNAL	746+07
	283.39	O_x 2+83	Metal Loss EXTERNAL	751+11
	283.66	O_x 2+84	Metal Loss EXTERNAL	751+49
	286.90	O_x 2+87	Metal Loss EXTERNAL	756+04
	288.66	O_x 2+89	Metal Loss EXTERNAL	758+49
	289.04	O_x 2+89	Metal Loss EXTERNAL	759+03
Ms_2	O_2 289.55	O_x 2+90	Metal Loss EXTERNAL	759+74
	289.99	2+90	Metal Loss EXTERNAL	760+36
765+44	293.61	2+94	AGM 02 - 765+44	765+44

Figure 5.4 AHEAD Equation to AGM 2

Figure 5.4 demonstrates the application of the rubber-banding equation between the Ahead portion of the given equation and the nearest downstream AGM.

Odometer	Event Description	Msx – Map Station – Unknown	Nearest Weld	Nearest AGM
	Launcher			
	WT CHANGE			
	WELD			
0.00	Valve AGM 01 - 356+78	356+78	D0.56	AGM 01
0.56	WELD	357+57		U0.56
4.76	WELD	363+45		U4.76
6.28	WELD	365+57		U6.28
16.31	Tap	379+60	D0.13	U16.31
16.44	WELD	379+78		U16.44
19.64	Tee	384+26	U3.20	U19.64
22.72	Metal in Close Prox	388+57	D0.27	U22.72
23.00	WELD	388+95		U23.00
25.53	Clamp	392+50	D0.95	U25.53
26.48	WELD	393+82		U26.48
39.83	Equation:412+50 BK = 409+69 AH	412+50	D0.09	U39.83
39.83	Equation:412+50 BK = 409+69 AH	409+69	D0.09	U39.83
39.91	WT CHANGE	409+80	D0.01	U39.91
39.92	WELD	409+82		U39.92
58.45	Metal Loss EXTERNAL	435+78	D4.69	U58.45
63.03	WT CHANGE	442+21	D0.10	U63.03
63.13	WELD	442+35		U63.13
65.02	Stopple Fitting	445+00	D1.88	U65.02
65.99	Clamp	446+35	D0.92	U65.99
66.84	WT CHANGE	447+54	D0.07	U66.84
66.90	WELD	447+64		U66.90
106.66	WELD	503+36		U106.66
123.37	WELD	526+80		U123.37
172.07	WELD	595+06		D121.55
195.33	Metal in Close Prox	627+66	U23.26	D98.29
222.15	WELD	665+26		D71.46
275.80	WELD	740+48		D17.81
276.73	Metal Loss EXTERNAL	741+78	U0.93	D16.88
279.80	Metal Loss EXTERNAL	746+07	U3.99	D13.82
283.39	Metal Loss EXTERNAL	751+11	U7.59	D10.22
283.66	Metal Loss EXTERNAL	751+49	U7.85	D9.95
286.90	Metal Loss EXTERNAL	756+04	U11.10	D6.71
288.66	Metal Loss EXTERNAL	758+49	U12.85	D4.95
289.04	Metal Loss EXTERNAL	759+03	U13.23	D4.57
289.55	Metal Loss EXTERNAL	759+74	U13.74	D4.06
289.99	Metal Loss EXTERNAL	760+36	U14.18	D3.63
293.61	AGM 02 - 765+44	765+44	U17.81	AGM 02

Figure 5.5 Nearest Weld and AGM

Figure 5.5 is a derivative of Figure 5.4. The nearest downstream weld and AGM are calculated to facilitate the location of an anomaly.

Ideally, you would want to apply the rubber-banding equation between above ground markers (AGMs) but it is extremely important to verify beforehand that the survey station for each AGM is the same as the survey station for the corresponding feature along the pipeline. For example, if an AGM is benchmarked at a valve whose survey station is 356+78 then the corresponding AGM should also have a survey station of 356+78. In order to verify in this way, three things are needed: the alignment sheet for the corresponding in-line inspection, the operator's benchmarked AGM list, and the in-line inspection pipe tally or feature report.

The first step is to verify that the survey station assigned to each AGM is exactly the same as the subsequent location on the operators' alignment sheets. Step two would be to verify AGM survey stations (known locations) as stated on the in-line inspection pipe tally report is the same as those on the operator's alignment sheets and benchmarked AGM list. Once verification is completed and it is clear that all three sources reference the same survey stations then the rubber-banding equation can be used in the in-line inspection feature report.

Keep in mind, the primary reason to use the rubber-banding equation is to correlate the in-line inspection feature report data to the operator's corresponding alignment sheet data and not necessarily to correct the operators' alignment sheet survey stations (please note that correction is a beneficial by-product of the process). The correlation results are used to prepare confirmation digs and repair plans. Unless otherwise instructed, survey stations on an operator's alignment sheet should not be changed or modified for the simple reason that the alignment sheet's survey stations are directly associated with each one's corresponding historical data. Results of an alignment sheet and in-line inspection survey correlation can also be used to verify if features obtained from hard copy historical recorders actually pertain to the pipeline in question.

During the integrity management data collection process, hard copy records may be collected that display features on the pipeline that are not recorded on any other records or database. If the feature in question is metallic, such as a sleeve or casing, the feature, along with its survey station can be compared to sleeves or casings recorded by an MFL tool.

Figure 5.6 and Figure 5.7 demonstrate the correlation of hard copy records to in-line inspection survey findings. The objective of the comparisons shown is to determine whether the newly found sleeves or casings are present on the pipeline. This is done by matching hard copy records to in-line inspection results. If any of the hard copy records do not align with any of the features detected by the in-line inspection tool, then that may indicate that the feature is either non-metallic or no longer present. The next step to verify the existence of the feature in question would be to perform confirmation digs.

Begin Sleeve	End Sleeve	length		Begin Sleeve	End Sleeve	length
11118+01	11118+03	2.00				
11147+63	11147+65	2.00		11147+68	11147+70	2.00
11147+69	11147+70	1.00		11147+73	11147+75	2.00
11147+76	11147+77	1.00		11147+81	11147+82	1.00
11177+10	11177+18	8.00		11177+23	11177+31	8.00
11191+06	11191+08	2.00		11191+15	11191+17	2.00
11231+83	11231+89	6.00		11231+70	11231+72	2.00
				11232+05	11232+06	1.00
				11253+79	11253+87	8.00
11255+30	11255+51	21.00		11255+37	11255+58	21.00
11270+70	11270+81	11.00		11270+82	11270+93	11.00
11286+26	11286+34	8.00		11286+44	11286+52	8.00
11292+47	11292+49	2.00		11292+52	11292+54	2.00
11297+40	11297+44	4.00		11297+47	11297+51	4.00
11297+64	11297+67	3.00		11297+66	11297+68	2.00
11298+14	11298+37	23.00		11298+21	11298+43	22.00
				11347+32	11347+46	14.00
11385+91	11385+93	2.00		11385+91	11385+93	2.00
11624+07	11624+13	5.60		11624+05	11624+11	6.00
11694+49	11694+51	2.00		11694+46	11694+48	2.00

Figure 5.6 Historical Records

Begin Casing	End Casing	length		Begin Casing	End Casing	length
10647+17	10647+62	45				
				10540+23	10540+66	43.00
				10593+10	10593+58	48.00
10701+83	10702+39	56		10701+70	10702+26	56.00
				10729+49	10729+83	34.00
10815+73	10816+67	94		10815+73	10816+64	91.00
10971+97	10972+56	59		10971+91	10972+50	59.00
11078+22	11078+65	42		11078+23	11078+66	43.00
11138+72	11139+02	30				
11143+25	11144+40	115		11143+26	11144+40	114.00
11146+49	11147+09	61		11146+44	11147+04	60.00
11169+02	11169+54	52		11168+88	11169+40	52.00
11213+96	11214+39	44		11213+84	11214+28	44.00
11241+45	11242+19	74		11241+29	11242+03	74.00
11254+01	11254+98	97		11253+94	11254+90	96.00

Figure 5.7 Historical Records

5.4 Data Integration

Data integration is required in nearly all parts of an integrity program, including those early in the implementation. Integrity program elements that require data integration include:

HCA Segment Identification

The National Pipeline Mapping System (NPMS) defines a large portion of the HCAs that exist at many commercially navigable waterways, high population areas, other populated areas, and unusually sensitive areas in the United States. But, it does not describe HCAs for all situations that need to have an HCA defined. Examples of undefined situations include areas of occasional or informal public gatherings, i.e., picnic grounds, campgrounds, and sports fields. Additionally, the NPMS is updated only periodically and may not include new HCAs resulting from recent development.

Pipeline operators have the responsibility to identify these other and new HCAs, collect data generated by pipeline patrols, surveillance, and encroachment investigations, then analyze and integrate the data into their integrity programs.

Baseline Assessment Plan and Schedule

HCA regulations require that all HCA pipeline segments have baseline assessments made by prescribed deadlines with the 50% of the HCA segments with the highest integrity risks assessed in the first half of the baseline assessment period. In order to identify the 50% with the highest risks, enough solid, verifiable integrity information must be collected, integrated and analyzed.

Remedial and Preventive Actions

Integrity deficiencies identified by assessments and information analysis must be mitigated to reduce the risk of pipeline failures; the mitigative action data must be integrated into the program to reflect the improved condition of the pipeline and to re-prioritize further mitigation of other deficiencies.

5.4.1 Defect Assessment

5.4.1.1 Recognized Industry Methods

To accomplish good data integration, you must select a basis to correlate the integrity information. It should be one that best fits the pipeline system and/or the primary techniques used to assess the condition of individual pipelines that comprise the system.

- For pipelines of significant length, i.e., cross country transmission pipelines, the basis should correlate to specific sites where features change in ways that impact integrity.
- For shorter gas transmission lines that are part of gas distribution system, it is probably best to use entire transmission segments as the basis for data integration.

In-Line Inspection

Anomaly and feature listings resulting from in-line inspections provide a good basis for data integration. Most in-line inspection listings provide location information (such as pipeline survey stations) and descriptions.

Cathodic Protection Survey

Close interval electrical surveys, such as close interval potential surveys, also provide a good basis for data integration. Like in-line inspection, these surveys provide much of the location information and pipeline features.

Because of the enormous amount of integrity data compiled and the enormous amount of data manipulation required, computers must be used to integrate the data. There are basically three kinds of computer software available for data integration: spreadsheet, database, and custom software. Descriptions, advantages, and disadvantages of the software types are:

- **Spreadsheet Software**

  Pros

  Spreadsheet can be developed by operator personnel to compute and edit spreadsheet values. Macros add to the software's flexibility by creating a complex string of calculations and actions.

  Cons

  Spreadsheets have a limited functionality without macros.

- **Database Software**

  Pros

  Usually developed by third party vendors, databases can store, categorize, and manipulate an enormous amount of data. Database software is the primary way to maintain an integrity management program.

  Cons

  In order to modify database software it is necessary to contract the vendor or an independent programmer.

- **Custom Computer Software**

  Pros

  Often developed by operator personnel to perform redundant tasks, the software can usually be distributed to other operators without having to make code modifications.

  Cons

  Once the parameters of the task change, the software become obsolete.

5.4.1.2 Ranking Defects

An operator must evaluate any condition that could impair the integrity of the pipeline, and schedule remediation. Discovery of an anomalous condition occurs when an operator has sufficient data to determine a potential threat to the integrity of the pipeline exists. Within 180 days after an integrity assessment the operator must obtain sufficient information to verify the condition.

The first step is to prioritize the mitigation and/or repair on the basis of severity. ASME B31.8S section 5.5 states, "A first step in prioritization usually involves sorting each particular segment's risk results in decreasing order of over all risk. Similar sorting can also be achieved by separately considering decreased consequences or failure probability levels. The highest risk level segment shall be assigned a higher priority when deciding where to implement integrity assessment and/or mitigation actions."

Defects identified in HCAs are ranked higher than anomalous conditions found elsewhere along the pipeline. An operator's repair plan must meet the following requirements to schedule remediation of anomalous conditions.

Defects that require **immediate attention** are:

- Any anomalous condition within an HCA with metal loss greater then 80% of the nominal wall, regardless of dimensions, requires immediate repair.
- When calculation of the remaining pipe strength shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly, a repair is required.
- A dent located on the top of the pipeline between 90 degrees and 270 degrees and indicates metal loss, cracking, or a stress riser needs repair.
- A dent located on the top of the pipeline between 90 degrees and 270 degrees with a depth greater than 6% of the nominal pipe diameter must be fixed.
- When an anomaly exists, that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

Defects that require attention **within 60 days** are:

- A dent found on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter, i.e., greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12 must be repaired.

- When a dent located on the bottom of the pipeline has an indication of metal loss, cracking, or a stress riser, repair is needed.

Defects that require attention **within 180 days** are:

- When a dent is present with a depth greater than 2% of the pipelines 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, remediation is necessary.
- A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 2% of the pipeline diameter, i.e., 0.250 inches in depth for a pipeline diameter less than NPS 12, requires repair.
- A dent located on the bottom of the pipeline with a depth greater than 6% of the pipelines diameter needs remediation.
- When a calculation of remaining pipe strength shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly, repair is required.
- When there is an area of general corrosion with a predicted metal loss greater than 50% of the nominal wall, it must be repaired.
- When predicted metal loss greater than 50% of the nominal wall is located at a crossing with another pipeline, in an area with widespread circumferential corrosion, or in an area that could affect a girth weld, remediation is mandated.
- If a potential crack indication found during excavation is determined to be an actual crack, it must be fixed.
- When corrosion of or along a longitudinal seam weld exists, repairs must be made.
- A gouge or groove greater than 12.5% of the nominal wall requires repair.

Other Conditions

An operator must evaluate any other condition that could impair the integrity of the pipeline, and as appropriate, schedule remediation.

Each operator's integrity management program must create documentation of all repairs and/or inspections made to show that remediation will ensure the long term integrity of the pipeline.

5.4.1.3 Prioritizing Repair / Remediation of Defects for Investigation

The consequences of failure are key when assessing risks and prioritizing integrity deficiency mitigation. Consequences of failure include injury to the public and pipeline personnel, damage to nearby buildings and utilities, damage to nearby roadways and railroads, environmental pollution, interruption of service to pipeline customers, and the economics of mitigating integrity deficiencies. Some of the specific failure consequence factors that should be considered are:

- NPMS identified HCA locations
- Terrain and drainages
- Operator identified HCA locations
- Potential impacts
- Land use (e.g., urban, rural, farm)
- Product characteristics
- Population densities
- Product release volumes
- Impact zones
- Failure frequencies

It should be noted that the types of integrity data, integrity threats, and consequences of failures listed above do not constitute a comprehensive list of all integrity information needed for integrity information analysis. Differences in construction, operation, and maintenance practices among pipeline operators means individual operators must include additional and/or different information in their particular integrity analysis.

5.4.2 Threat Identification and Assessment (Internal and External Corrosion)

In order to identify what integrity information needs to be included in the integrity analysis, you must identify the conditions that threaten pipeline integrity. Fundamental integrity threats have been identified and categorized in the following way:

Material and Construction Defects
- Defective longitudinal pipe seam
- Defective pipe body
- Defective joint welds
- Other defective welds and fabrications
- Wrinkle bends
- Buckled pipe
- Inadequate support

Corrosion and Cracking Mechanisms
- External corrosion
- Internal corrosion
- Atmospheric corrosion
- Microbiologically induced corrosion
- Stress corrosion cracking
- Other cracking mechanisms
- Environmental contamination

Mechanical Damage
- Construction damage
- Maintenance damage
- Third party excavation damage
- Accidental damage by public
- Vandalism
- Terrorism

Device Failures and Malfunctions
- Flange gaskets and O-ring leaks
- Packing and seal leaks
- Pipe coupling failures
- Control equipment malfunctions
- Relief equipment malfunctions

- Inoperable valves
- Electric power failures
- Cathodic protection failures

Operations
- Incorrect operations
- Incorrect operating procedures

Weather Related
- High winds
- Rough seas
- Cold temperatures
- Hot temperatures
- Lightning strikes
- Heavy rains
- Flooding

Earth Forces
- Earthquakes
- Land slips
- Subsidence and settlement
- Telluric (geomagnetic) currents

Other Conditions
- Significant changes since last assessment
- Mechanical damage on top of pipe
- Anomalies abrupt in nature
- Anomalies oriented longitudinally on pipe
- Anomalies with large areas
- Anomalies inside or near casings
- Anomalies at pipeline crossings
- Anomalies in areas with suspect CP

Threats vary from pipeline to pipeline and from location to location. It is essential that personnel with intimate knowledge of a pipeline system be involved in identifying the threats.

5.4.3 Integration and Interpretation of Integrity Related Data

The importance of developing and implementing sound data integration procedures cannot be over emphasized. If done effectively, integrity management costs and lost time are kept at a minimum. But if data integration is not done properly, it can lead to costly repair plans or loss of life. The primary expected result from data integration is to make all integrity information readily available for risk analysis and assessment. It should be formatted to make it easy to identify integrity issues and risks and/or failure consequences that cannot be determined accurately using only a few pieces of integrity information, particularly in HCAs.

API standard 1160 makes clear that the use of copy records (whether past or present) has a great deal to do with the quality of risk assessment inspections. The true value of having integrity management is to accurately assess potential harm to people, the environment, and the pipeline. For any integrity management program to function correctly as much accurate information as possible should be incorporated into it; an advantage to an integrity management program is that data from different sources can be cross-referenced.

ASME B31.8S Section 4.5 “Data Integration” states “For integrity management program applications, one of the first data integration steps includes development of a common reference system (and consistent measurement units) that will allow data elements from various sources to be combined and accurately associated with common pipeline location.”

“Individual data elements shall be brought together and analyzed in their context to realize the full value of integrity management and risk assessment. A major strength of an effective integrity management program lies in its ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence that a specific threat may or may not apply to a pipeline segment. It can also lead to an improved analysis of overall risk.”

Using the same measurement units makes it possible to carry out database searches, actions, and analysis. You can't calculate with dissimilar units and analysis is impossible. Pipeline attributes must be named in consistently or accurate data correlation is impossible. Once a naming structure (nomenclature) is in place and the same measurement units used, data can then be imported into the operators' integrity management application for comparison, computation and analysis.

Normalizing (structured nomenclature and measurement units) data is particularly important when correlating historical hard copy records, alignment sheets, in-line inspection and direct assessment results with each another. Since anomalies in high consequence areas take precedence over any others, it is extremely important to have accurate, relatable data to correlate. This prevents the possibility of identifying an incorrect location for an anomaly. A mistake in location could result in increased regulatory compliance costs or repair of an anomaly that only requires monitoring.

Many pipeline condition inspection techniques i.e., in-line inspect-ion, will, by themselves without integrating other data, identify integrity issues that require mitigation. However, individual condition inspection techniques frequently will not, by themselves, identify integrity issues. The severity and risks associated with those integrity deficiencies might not be recognized without integrating other integrity data. The following examples detail failures in which single pieces of integrity information did not accurately portray the integrity deficiencies or their risks; intergrating pertinent integrity data would certainly have identified, analyzed, and mitigated the integrity deficiencies and their risks before the failures occurred.

External Corrosion

An external corrosion rupture occurred on a 60-year-old pipeline that crosses a river in a rural area. A close interval pipe-to-soil potential survey indicated cathodic protection was marginal at the river crossing. River crossing inspections indicated soil cover over the pipeline was minimal, the pipe was exposed at some locations, and soil cover depths changed considerably from inspection to inspection. Resistivity of the soil in the river was relatively low in magnitude and, therefore, corrosive. Integration and analysis of all of this information would likely have indicated the need for close inspection of the river-crossing pipe.

Electrical Interference Damage

This example involves electrical interference damage from a foreign-owned cathodic protection system on a 25-year-old pipeline in a rural area. Annual cathodic protection surveys indicated that protection was marginal, but met cathodic protection criteria at fixed test stations in an area where several foreign-owned pipelines existed. (Close interval pipe-to-soil potential survey had not been performed on the pipeline.) The locations of the foreign pipelines and their cathodic protection systems were known. Integration of all of this information would probably have indicated the need for a close interval pipe-to-soil potential survey and/or interference testing, either of which would likely have indicated the potential for electrical interference damage.

Internal Corrosion

This example involves internal corrosion of dead-end piping in a gas compressor station. The compressor station had undergone modification in the recent past and the piping was hydrostatically tested after the modifications. The carbon dioxide content in the gas was slightly elevated. Test water and corrosive contaminants were inadvertently left trapped in a section of dead-end piping on the discharge side of the station where pressure and temperature were higher. These conditions caused very aggressive internal corrosion to occur. Integration of all the data would likely have indicated the potential for internal corrosion and the need for further investigation.

Atmospheric Corrosion

In this case, atmospheric corrosion of a 45-year-old gas pipeline inside a casing under a major highway on the discharge side of a compressor station occurred. The pipeline was coated with coal tar enamel. Although, the soil was well drained at the highway crossing the moisture content of the air circulating through the casing vents was high much of the time. During the years of operation, gas temperatures were periodically elevated above the upper temperature limits of the coating, which caused the coating to soften and flow from the top of the pipe. These conditions caused atmospheric corrosion to slowly corrode the pipe inside the casing. Integration of this information would likely have indicated the need for detailed testing.

Mechanical Damage

This example involves mechanical damage to a 1950s-vintage hazardous liquids pipeline at a location where underground utilities had been constructed a few years prior to the failure. The way the pipeline was operated caused frequent, broad pressure fluctuations. A close interval pipe-to-soil potential survey made a few years prior to nearby construction indicated acceptable, uniform levels of cathodic protection throughout the construction area. A close interval survey performed soon after the construction showed marginal-to-inadequate cathodic protection in the immediate area of the construction. Third party construction made a dent with a gouge, and damaged the coating; the pipeline eventually failed from cyclic fatigue. Integration of the two close interval surveys, and in particular, the abrupt change of cathodic protection levels between them, along with construction activities, would have indicated the need for further investigation.

Weather Related

This example involves weather-related damage to a large diameter gas pipeline at a river crossing in a wide, shallow flood plain composed primarily of sand. During construction the pipeline was provided with river weights in the river, but not across the flood plain. Depth of cover surveys across the flood plain indicated that the soil cover was eroding from rains and flooding and was minimal at some locations. An unusually heavy rain and subsequent flooding caused the pipeline to float; stresses caused by movement of the pipeline caused it to rupture. Integration of information related to soil cover and erosion, lack of river weights in the flood plain, and the propensity of the pipe to float would have indicated the need for mitigative action.

5.5 Summary

Pipeline operators have made use of pipeline integrity management techniques for as long as pipelines have been in operation, but not to the level now required by regulators. Operators must now have integrity management programs that use a broad range of techniques in very structured routines. Clearly, the fundamental basis in an effective integrity management program is integration of all relevant integrity data in ways that are meaningful to individual pipeline operators. To be meaningful, the data must be correlated in formats that allow pipeline operators to identify and prioritize integrity deficiencies easily so remedial and preventive actions can be taken before pipeline failures occur. Information integration routines must also be flexible to accommodate changes in pipeline systems, in public and environmental exposures, new operating and maintenance information, new and improving technology, and new or amended regulations.

References

Federal Registrar, U.S. Code of Federal Regulations (CFR) Title 49, “Pipeline Integrity Management in High Consequence Areas,” Part of 195§195.452 (Washington, D.C.; Office of the Federal Register, Department of Transportation, Research and Special Programs Administration.)

Federal Registrar, U.S. Code of Federal Regulations (CFR) Title 49, “Pipeline Integrity Management in Unusually Sensitive Areas,” Part of 195§6 (Washington, D.C.; Office of the Federal Register, Department of Transportation, Research and Special Programs Administration.)

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Det Norske VERITAS (DNV) Recommended Practice RP-F101, “Corroded Pipelines.”

Review of Integrity Management for Natural Gas Transmission Pipelines, Gas Piping Technology Committee Technical Report.

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

Chapter 6: Risk Assessment

After completing this chapter, students should be able to:

- Define risk, risk assessment, and integrity verification.
- Comprehend the objectives of risk assessment and risk assessment methodology.
- Understand the objectives and the processes of integrity verification.
- Describe the fundamental capabilities of integrity verification tools.
- Be familiar with the history and probability of pipeline failures.
- Know the process of consequence analysis.
- Know the distinctions between prescriptive and performance based risk assessment.
- Be familiar with quantification of risk, relative and absolute

6.1 Risk Assessment

6.1.1 Definition

Risk is a measure of loss or negative outcome in terms of both the probability of an event's occurrence and the magnitude of its consequence. It is, therefore, a function of an event's *probability* of occurrence and its associated *consequence*. Consequence can be measured in a variety of ways, depending on its nature. For cases involving human health and safety, consequences may be measured by fatalities or injuries. For cases involving environmental damage, consequences may be measured by the cost required to repair the damage and restore the affected environment.

When probability and consequence are expressed numerically, risk is the product. For example, the overall risk to pipeline integrity of the nine categories of failure types (ASME B31.8S) may be given as:

$$\text{Risk} = P_1 \times C_1 + P_2 \times C_2 + P_3 \times C_3 + P_4 \times C_4 + P_5 \times C_5 + \ldots\ldots + P_9 \times C_9$$

Risk assessment is, therefore, a systematic analytical process which includes the use of a variety of information for risk

- identification,
- analysis,
- evaluation,
- mitigation,
- acceptance.

Such information could derive from historical data, theoretical analysis, informed opinion of subject matter experts (SMEs), and concerns of stakeholders.

For pipeline integrity consideration, risk assessment addresses hazards, consequences, and probability in pipeline hazardous materials transportation. It demands a thorough and comprehensive knowledge of each pipeline segment and its relationship with the overall pipeline system.

For pipeline integrity, overall risk assessment includes:

- Prioritization of pipeline/segments for scheduling integrity assessments and mitigation action
- Assessment of the benefits derived from a mitigation action
- Determination of the most effective mitigation measures for the identified threats
- Assessment of the integrity impact from modified inspection intervals
- Assessment of the use of or need for alternative inspection methods
- Effectiveness of resource allocation.

It is a continuous process, which is most effective if integrated into daily pipeline operation. The principles of risk assessment assign the highest priority to locations subject to the greatest combination of probability and consequence. The proper use of risk assessment principles can help pipeline operators maintain the flow of pipeline integrity data and the analysis of this data by responsible parties.

6.2 Overview of Risk Assessment Objectives

Risk assessment is a component of the overall process of risk management, which is the systematic application of policies, practices, and resources to risk assessment and the control of risk that affect human health, safety and the environment (HSE). In order to manage risks, the data collected during a pipeline pre-assessment are used to conduct a risk assessment. The risk assessment process identifies the location-specific events and/or conditions that could lead to a pipeline failure, and provides an understanding of the likelihood and consequences of an event. The results of a risk assessment should include the potential severity and location of risks throughout the pipeline.

For pipeline integrity, the overall objectives of risk assessment are:

•Prioritization of pipelines/segments for scheduling integrity assessments and mitigation action

•Assessment of the benefits derived from mitigation action

•Determination of the most effective mitigation measures for identified threats

•Assessment of the integrity impact from modified inspection intervals

•Assessment of the need for alternative inspection methodologies and

•Effective resource allocations.

Relative risk is the key to prioritization. This entails the comparative risk analysis of a pipeline/segment to another pipeline/segment in order to differentiate and provide a relative priority for integrity assessment. Risk evaluation is the key to mitigation decisions. This entails the comparison of the estimated risk criteria against the given risk criteria to establish the significance of the identified risk. To perform these tasks requires the use of reliable risk assessment methodology.

Selecting an appropriate risk assessment method requires the pipeline operator to think hard about many issues including public heath, public safety and preservation of the environment.

Responsibility for sound pipeline integrity resides with management. Discovery of pipeline leaks can result in felony conviction of individuals, individual and corporate fines, and individual and corporate civil penalties. Fines can reach into the millions of dollars.

Management wants the risk assessment to link specific risks to appropriate inspection and/or mitigation activities. Management would like to foresee the possible decision scenarios that could be based on the results of the risk assessment. Vice-versa, they would like to anticipate the nature of risk assessment results they would need to support a sound decision-making process. They would want to have a clear idea of the level of commitment and/or resources that would be required to successfully implement a comprehensive risk assessment in particular, and integrity management in general. Because time is money, the urgency, or lack thereof, for risk assessment results is an important parameter. In short, the general objectives of management incorporate the following elements relating to pipeline integrity threats:

- Identification of hazards – those undesirable risk-increasing conditions that could result in an incident;
- An understanding of the consequences in the event of an incident;
- Regulatory compliance requirements;
- Comprehensive data gathering programs;
- Appropriate algorithm for ranking risk significance of each hazard; an algorithm needs to be tempered with the belief system, failure statistics, pipeline operation and maintenance practices;
- A relative risk matrix that may ultimately be used to confirm if the calculated risk is manageable or unmanageable;
- Risk/benefit analysis of potential projects;
- Risk reduction objectives and goals - what is the acceptable level of residual risk;

- A continuous improvement culture-this could ensure that risk factors are reduced and residual risk is minimized or eliminated in the future;
- Monitoring systems - this could ensure that new operating practices are risk averse.

The processes of data collection, review, analysis, and integration should be in place from conception of the integrity management program. This process should start with a sound design, a sound material selection strategy, and a sound construction philosophy. Compiling the data and developing a usable database are crucial. The process of planning, assessing, and evaluating on an iterative basis will provide better data to perform the next risk assessment.

Often, various data sets are used together to achieve the desired level of synergy. For example, the results of in-line inspection may be used in combination with close-interval survey results and/or direct current voltage gradient results to locate a potentially serious integrity risk. Therefore, data and metadata are key elements in risk assessment, the precursor to integrity assessment. Pipeline corrosion integrity management normally requires data sets that influence risk assessments about time-dependent threats: internal corrosion, external corrosion, and stress corrosion cracking.

6.3 History of Failure/Probability of Failure

In everyday terminology, probability is a numerical measure of the likelihood that a particular event will occur. For a given event, such a numerical measure could be the ratio of the number of the event's outcomes to the total number of possible outcomes of an exhaustive set of equally likely outcomes. The probability of pipeline failure for each category of integrity threat may therefore be estimated from an "exhaustive" set of documented historical failure events due to that particular threat. History of pipeline failure is therefore a logical place to begin.

The pie diagram (Figure 6.1) documents the causes of natural gas transmission pipeline failures in the U.S. from 1984 to 1990. This may be compared with the historical causes of pipeline failure from 1983 to 1995 in Alberta, Canada depicted in Figure 6.2.

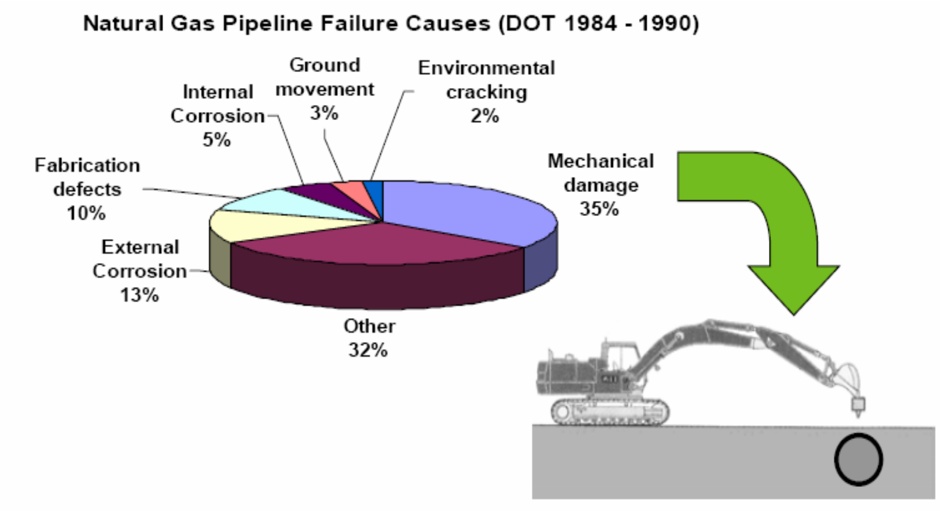


Figure 6.1 History of Natural Gas Transmission Pipeline Failures and Failure Causes in the U.S.
(Source: CO_2 Capture & Storage Workshop, Alberta, Canada, 2006)

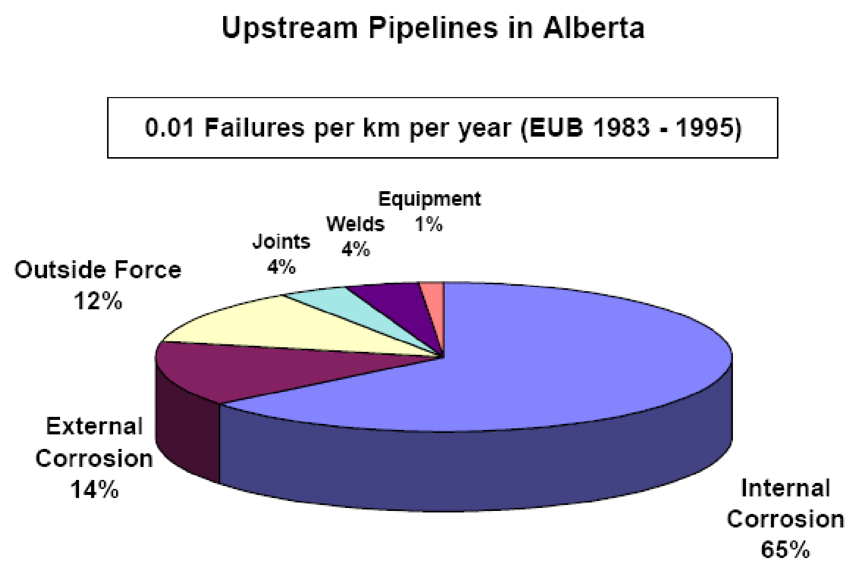


Figure 6.2 History of Upstream Pipeline Failures and Failure Causes in Alberta, Canada
(Source: CO_2 Capture & Storage Workshop, Alberta, Canada, 2006)

According to the Office of Pipeline Safety, in 2002 internal corrosion alone caused 18 percent of all transmission pipeline incidents. Indeed, external corrosion, internal corrosion, and stress corrosion cracking constitute about 30% of the reported cases of hazardous liquid and gas transmission incidents worldwide. When pipeline integrity is compromised by corrosion, the probability of potentially deleterious impact on health, safety, environment (HSE), and the economy is high.

NACE defines corrosion simply as the deterioration of material (usually a metal) due to reaction with its environment. Corrosion is a material property. The energy released when a metal converts to corrosion products is the driving force for its corrosion. That is, corrosion cannot be stopped; it can only be controlled. Controlling pipeline corrosion entails controlling such variables as oil field fluid conductivity, soil resistivity, electrolyte, pH, dissolved gases, intensity of microbiological activities, temperature, pressure, fluid mechanics, etc. For example, most oil wells do not have internal corrosion problems until water is produced. Similarly, pipelines buried in bone-dry soil suffers little or no corrosion, until water from whatever source unleashes the corrosive power of the variety of mineral matter in soil. Pipeline stress corrosion cracking will not occur in the absence of stress and a corresponding hostile environment.

When pipeline corrosion control system is ineffective or non-existent, there is a high likelihood that its integrity would be compromised resulting in pipeline failure. In what follows, an overview of the history of such pipeline failures is presented.

6.3.1 History of Pipeline Failures

Before considering the history of pipeline failures, it is perhaps instructive to compare the failure rates in the U.S. for all modes of oil transportation. The failure rate for transmission pipeline, in terms of fatalities, injuries, and fires/explosions is the lowest when compared with rail, tank ships, barges, and trucks, according to the Association of Oil Pipelines. However, high-pressure transmission pipeline ruptures are catastrophic when they occur.

Historically, important ruptures with significant individual and societal impact are illustrated in Table 6.1 Recognition of the societal impact has significantly elevated global focus on pipeline integrity. Health, safety, and environmental concerns now drive government regulations worldwide. The essential goal of pipeline integrity management is to minimize as low as reasonably practical (ALARP) the recurring nature of pipeline failures.

Publicly available pipeline databases normally report incident rates in units of incidents per 1,000 miles per year, providing a means of predicting the number of incidents for a given length of pipeline, over a given period. This reporting format is, in principle, equivalent to saying that 1.0 incident per 1,000 miles in 1.0 year implies that a one-mile long pipeline will have 1.0 incident in 1,000 years or 1/1000th of an incident per year. This sort of implication is clearly unrealistic, but a basis for comparison is needed for the general category of operating pipelines.

Although a basis for the reporting format existed and the reportable incidents were usually well documented, the pipeline lengths involved were not as well documented. New constructions or pipeline abandonments were not necessarily included in the database and this adversely affected the accuracy of the corresponding incident rates. Aside from this, ***the reporting criteria became the key determinants for the generally reported incident rate since the inception of reporting pipeline failure rates.***

For example, in Western Europe from 1981 to 1991, oil spills greater than one cubic meter (264 gallons or 6 barrels) are reportable. Spills below that limit are reportable if, and only if, it has a noteworthy impact on the environment. With these criteria, the incident rate of oil spillage from 1981 through 1994 is 0.85 per 1,000 miles/year.

For U.S. natural gas transmission and gathering lines from 1984 to 1992, the leak criteria prescribed by the U.S. Department of Transportation was:

1. Events, which involved a release of gas from a pipeline or of LNG or gas from an LNG facility, which caused: (a) a fatality, or personal injury necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, or both, of $50,000 or more.
2. An event which resulted in an emergency shut-down of an LNG facility.
3. An event that was significant, in the judgment of the operator, even though it did not meet any of the above criteria.

Based on these criteria for natural gas transmission and gathering lines from 1984 to 1992 in the U.S., the incident rate is 0.26 per 1,000 miles per year. On the other hand, between 1970 and 1984, the reporting criteria were much more stringent, requiring the reporting of leaks causing less than $5,000. The incident rate was correspondingly higher i.e., 1.3 incident rate per 1,000 miles per year for essentially the same length of pipeline in the country. The obvious conclusion derived from the above data is that the reporting criteria are the key determinants for any generally reported historical incident rate.

This conclusion is further confirmed by considering the U.S. hazardous liquid pipeline accidents from 1986 through 1992. The leak criteria prescribed by the U.S. Department of Transportation for incidents are:

- Explosion or fire not intentionally set by the operator,
- Loss of more than 50 barrels of liquid or carbon dioxide,
- Escape to the atmosphere of more than five barrels per day of highly volatile liquid,
- Death of any person,
- Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or normal activities beyond the day of the incident, and/or
- Estimated property damage to the property of the operator, or others, or both, exceeding $5,000.

Based on the criteria, the incident rate was a 1.3-incident rate per 1,000 miles per year, which is almost the same as the reportable accident for natural gas transmission and gathering lines from 1970 and 1984, requiring the reporting of leaks causing less than $5,000. Hence, the reporting criteria are to blame for skewing the results.

The consolidated data, based on the California State Fire Marshall (CSFM) regulated interstate and intrastate hazardous liquid pipelines, support the same conclusion. This extensive historical database includes all leaks, regardless of size, extent of property damage, or extent of injury. Using this data as well as those corresponding to the various dollar amounts (based on 1994 U.S.$), the uncorrected pipeline incident rate for various pipeline events is 7.1. That is, the incident rate depends on the incident reporting criteria and, therefore, ***the failure probabilities estimated from publicly available histories of failure are not sufficiently definitive***.

Nonetheless, the failure probability values could be used to develop a relative probability of failure associated with a proposed pipeline project. In doing this, it needs to be noted that each pipeline network is unique and documented attributes of a failed pipeline may not be specifically the same as the pipeline whose risk assessment is under consideration. Using the history of failure to develop probability of failure requires that proper consideration be given to the following:

- Type of proposed pipeline
- The contents being transported
- Age of the pipe
- Type of coating
- Operating conditions
- Other pipeline specific parameters

In spite of the limitations of historical data, they do enable performance benchmarking for industry best practices in pipeline integrity management. For example, Table 6.1 presents a comparison of worldwide pipeline failure rates illustrating that the lowest historical failure rates in both oil and gas pipelines occurred in Western Europe and Canada. Available statistics also show that the top operators who experience low failure rates do so with a 30% to 70% lower operation and maintenance expenditure.

Table 6.1: Comparison of Worldwide Pipeline Failure Rates

Region	Product	Failure Rate, per 1000, km/ years	Years
United States	Gas	1.18	1984-92
United States	Oil	0.56-1.33	1984-92
Europe	Gas	1.85	1984-92
Europe	Oil	0.83	1984-92
Western Europe	Oil	0.43	1991-95
Western Europe	Gas	0.48	1971-97
Canada	Oil and Gas	0.35	NA
Hungary	Oil and Gas	4.03	NA
Nigeria	Oil	6.40	1976-95

Source: Pigging Products and Services Association, 2004. (The data for Hungary has also been reported separately as it is the only Eastern European country with its own country-specific data.)

6.3.2 Probability of Pipeline Failures

Despite the universal acceptance of excellent codes of practice for design, manufacturing, installation, and construction, plus the high integrity of pipeline operation, inspection, maintenance and safety measures, pipelines do fail with varying degrees of severity. The failure frequency and consequences generally depend on pipeline resistance to damage and/or deterioration, design factors, threat characteristics, failure modes, operating stresses, safety systems, protection systems, instrumentation, and the probability of human error. Because of this, a risk assessment is normally carried out before a new pipeline is built. This involves probability and consequence analysis to identify the likelihood of a pipeline incident as well as the potential severity of its attendant impact on health, safety, environment (HSE) and the economy.

The probability or frequency of occurrence of pipeline failure for a given threat can be estimated qualitatively or quantitatively. The first method is qualitative and it relies on subject matter experts (SMEs). These are individuals who have enough expertise in specific areas of operation to provide qualitative data using sound engineering judgment and are able to assign specific values ranging from 1-3 for P_i reflecting high, medium, or low ***probability***.

The second method is quantitative. The probability of pipeline failure can be estimated from the historical failure rate per mile (or kilometer) due to that specific threat, from failure sequence models such as fault trees, event trees, or from some special failure models.

Considering corrosion threat alone, the U.S. Department of Transportation, Office of Pipeline Safety, reports that corrosion was responsible for 19% to 41% of pipeline failures over the time between 1994 and 2000. During the same time, there were 528 pipeline incidents in an average 297,548 miles of natural gas transmission pipelines. This is equivalent to a failure rate of 0.25 per 1,000 miles per year.

The following simple hypothetical example is used to illustrate the probability of failure calculation for a new 40-mile natural gas pipeline:

Example 7.1: *Consider that a new 40-mile natural gas pipeline is being planned and that 41% of pipeline incidents are due to corrosion. During prior years, the pipeline failure rate is 0.25 per 1,000 miles per year. What would be the probability of a pipeline incident due to corrosion in the new 40-mile pipeline? No information is available about possible corrosion type, defect dimension and/or growth rate, pipeline diameter, pipeline wall thickness, pipe material properties, operating pressures, etc.*

Problem solution:

The deterioration mechanism is corrosion

*The failure frequency due to corrosion (per 1,000 miles per year) = 0.41*0.25 = 0.1*

The failure frequency, F_o, for the new 40-mile pipeline is given by:

*F_o (failure frequency/year) = 0.10 /1,000 * 40 miles*

F_o (failure frequency/year) = 0.0040

The probability of a pipeline incident, P_c, caused by corrosion within the new 40-mile segment can be calculated from the failure frequency (0.004) within 1 year as follows:

$P_c = 1.0 - e^{(Fo * t)}$

$P_c = 1.0 - expo\ (0.0040*1)$

$P_c = 1.0 - 0.996$

$P_c = 0.004$

The probability of pipeline failure within the new 40-mile segment is 0.004 or approximately one pipeline failure in 250 years. If the pipeline were 400 miles long, the failure probability would be 0.039 or approximately one pipeline failure in 25.5 years.

There are many flaws in the above example and solution. The first and most important relates to time independence. Corrosion is a time-dependent phenomenon and the probability of corrosion-induced pipeline failure must reflect that. In addition, the method does not address the corrosion type, failure modes, defect dimension and growth rate, the pipe diameter and wall thickness, the pipe material properties and operating pressures, etc. A more rigorous method of estimating the probability of pipeline failure would relate to all of these factors as well as the uncertainties associated with each. The formalism for such a method, beginning with historical data, could be expressed as follows:

Probability function for pipeline failure/mile = Number of defects/ mile x *Failure probability density per defect*

The failure probability density distribution per defect could be derived from inspection data and it depends on the characteristic length parameter, which is unique to the specific corrosion mechanism and the relevant pipe dimensions. For pitting corrosion, the characteristic length would be a function of the maximum pit depth and for general corrosion, it would be a function of corroded length, breadth and depth. As long as the required data is available for a particular threat, one could develop a probability density distribution for it. Such probability density distributions could be developed for various threats including internal corrosion, external corrosion, stress corrosion cracking, ground movement, mechanical damage, weld, fabrication defects, and others.

An example of an appropriate formalism is schematically illustrated in Figure 6.3.

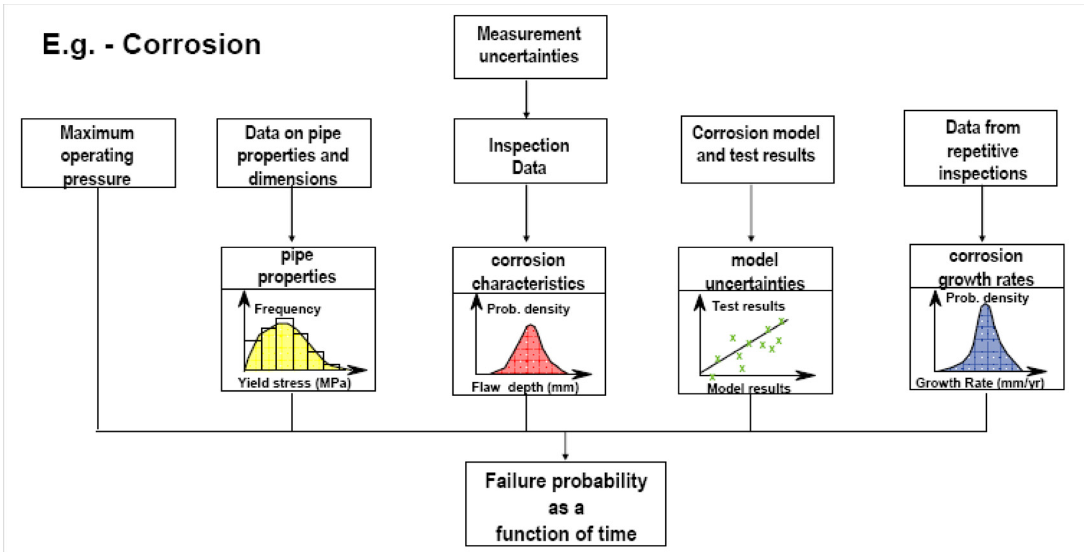


Figure 6.3 Probability Estimation Using a Suitable Algorithm
(Source: CO_2 Capture & Storage Workshop, Alberta, Canada, 2006)

Using corrosion as an example, the time-dependent failure probability function can be estimated from a suitable algorithm that incorporates the following terms: (1) the maximum operating pressure, (2) yield stress frequency distribution based on the pipe properties and dimensions, (3) corrosion probability density characteristics derived from ILI data, (4) a reliable corrosion mathematical model including its error band, and (5) the corrosion growth rate probability density derived from repetitive inspection data.

Although this a more accurate method to estimate failure probability, the following uncertainties do exist:

- Both internal (e.g., possible overpressure) and outside (e.g., third-party impact) loads imposed on the pipeline
- Measurements of number and size of corrosion defects, defect growth rates, material properties (yield strength, fracture toughness), etc.

- Specific features of the pipe (specifications, age, diameter, thickness, joint type, weld type, seam type) etc.
- Site-specific features that might affect the corrosion mechanisms
- The modeling assumptions and approximations

Therefore, estimated failure probability functions cannot be exact but they do provide an acceptable basis for comparison as long as the best possible assumptions are made and the computational algorithm is internally consistent.

6.4 Consequence Analysis

Consequence analysis encompasses understanding the downstream effects of pipeline incidents that could release natural gas, oil and/or other potentially hazardous or toxic substances into the atmosphere. Specifically, consequence analysis focuses on the effects on individual and societal health, safety, the environment, and the economy. It assesses how many people could be killed and/or injured, what infrastructure would be destroyed/damaged, which operations would be affected, whose supply would be disrupted, what the possible shortage impacts would be, how large the economic impact would be, etc.

The analysis includes consideration of the following:

- Pipeline design criteria/attributes
- Potential causes of pipeline failures
- Spill sizes
- Leak detection
- Product characteristics
- Availability of nearby fire stations
- Pipeline warning markers
- “Safe-shutdown” valves at strategic high-consequence locations
- Evacuation

- Emergency response plans, including maps showing various danger zones, for fire, toxicity, overpressure, thermal effects, etc.

Consequence estimation is the methodology used to determine the potential for damage or injury from specific incidents. At this juncture, it is perhaps instructive to take a retrospective view of the reported consequence statistics for the past 10-year period, 1986 to 2006, for the U.S. pipeline failures, summarized in Table 6.2 for hazardous liquid transmission and Table 6.3 for natural gas transmission.

Table 6.2: U.S. Incident Summary Consequence Statistics From 1986 To 2006 (Hazardous Liquid Transmission)

Year	No. of Accidents	Fatalities	Injuries	Property Damage	Gross Loss (Bbls)	Net Loss (Bbls)
1986	210	4	32	$16,077,846	282,791	220,317
1987	237	3	20	$13,140,434	395,854	312,794
1988	193	2	19	$32,414,912	198,397	114,251
1989	163	3	38	$8,813,604	201,758	121,179
1990	180	3	7	$15,720,422	124,277	54,663
1991	216	0	9	$37,788,944	200,567	55,774
1992	212	5	38	$39,146,062	137,065	68,810
1993	229	0	10	$28,873,651	116,802	57,559
1994	245	1	7	$62,166,058	164,387	114,002
1995	188	3	11	$32,518,689	110,237	53,113
1996	194	5	13	$85,136,315	160,316	100,949
1997	171	0	5	$55,186,642	195,549	103,129
1998	153	2	6	$63,308,923	149,500	60,791
1999	167	4	20	$86,355,560	167,230	104,487
2000	146	1	4	$180,155,745	108,652	56,953
2001	130	0	10	$25,346,751	98,348	77,456
2002	147	1	0	$47,410,656	95,642	77,269
2003	131	0	5	$49,587,293	80,112	50,523
2004	144	5	16	$145,833,176	88,216	68,558
2005	137	2	2	$94,783,341	135,740	45,448
2006	86	0	0	$29,507,575	76,639	15,494
Totals	**3,679**	**44**	**272**	**$1,149,272,599**	**3,288,080**	**1,933,519**

Table 6.3: U.S. Incident Summary Consequence Statistics from 1986 to 2006 (Natural Gas Transmission)

Year	No. of Incidents	Fatalities	Injuries	Property Damage
1986	83	6	20	$11,166,262
1987	70	0	15	$4,720,466
1988	89	2	11	$9,316,078
1989	103	22	28	$20,458,939
1990	89	0	17	$11,302,316
1991	71	0	12	$11,931,238
1992	74	3	15	$24,578,165
1993	95	1	17	$23,035,268
1994	81	0	22	$45,170,293
1995	64	2	10	$9,957,750
1996	77	1	5	$13,078,474
1997	73	1	5	$12,078,117
1998	99	1	11	$44,487,310
1999	54	2	8	$17,695,937
2000	80	15	18	$17,868,261
2001	87	2	5	$23,674,225
2002	82	1	5	$26,713,069
2003	97	1	8	$49,540,561
2004	123	0	3	$68,179,092
2005	182	0	7	$269,307,752
2006	107	1	3	$43,225,678
Totals	**1,880**	**61**	**245**	**$757,485,251**

Accidents involving high-pressure gas pipelines have the potential for significant consequences primarily because the gas dispersion could be in the form of jet and/or cloud. The rate of release has a direct correlation on the rate of dispersion. Jet and pool fire ignition occurs immediately after loss of containment, with immediate radiation effects on people and property. Pool and jet fires generally tend to be localized and are of concern because of their potential for the domino effect, which depend on factors such as flammability, combustibility, amount of material released, temperature, humidity and flame spread. Assessment of the potential impact of a jet and/or pool fire requires appropriate heat flux radiation modeling that considers weather scenarios.

Vapor cloud fire has a delayed ignition point but its thermal radiation could be significant. Vapor cloud explosion could be equally catastrophic, not only because of the explosion, but because of its attendant overpressure. Because of the possible presence of hydrogen sulfide, toxic vapor cloud would need to be appropriately modeled to estimate the distances likely to be affected by the gas released. The characteristics of high consequence areas (HCA) and the potential physical pathways between pipelines and HCAs are important parameters for all consequence analysis.

The consequence of pipeline failure for a given threat can be estimated in two ways. The first method is qualitative and it relies on subject matter experts (SMEs). These individuals have enough expertise in specific areas of operation to provide qualitative data using sound engineering judgment and are able to assign specific cost values ranging from A-E for C_i representing either a high, medium, or low *consequence* category. Each consequence category can be associated with a financial cost.

The second method is quantitative. To estimate consequence areas for a prescriptive based program, the radius of the potential impact circle is calculated using the following equation:

$$r = 0.69 * d \sqrt{p}$$

(Note: 0.69 is the factor for natural gas; other gases or rich natural gas would use differing factors depending on their combustion point.)

d = outside diameter

p = pipeline segment's maximum allowable operating pressure, psig

r = radius of impact, ft.

The potential impact area extends from the center of the first affected circle to the center of the second affected circle. The count of housing units, infrastructure, and natural attributes within the potential impact area provide an estimate of the relative consequences to people, property, infrastructure, and the environment.

There are other equations to define the impact zones for hazardous liquids. The terminology for some of these factors are: leak impact factor (LIF), relative quantity of liquid or vapor (LV), relative range of leak (D), all things that could be damaged (R) and product hazard (PH). The leak impact factor is given by the following equation:

LIF = PH + LV x R

To calculate the consequences of a pipeline failure, a prescriptive-based program uses a variety of quantitative methods including logic models, scenarios, event trees, fault trees, threat-specific historical failure data based on the process fluids, operating variables, failure mode, as well as other internal and external variables. In most respects, the concepts of Quantitative Risk Assessment (QRA), a prescriptive methodology, are enumerated here. Issues that must be quantified include release, effects of un-ignited gas release, injury, population density, proximity, people, property, infrastructure, environment, topography, fire, meteorology, topography, dike, drainage, potential for secondary failures, service interruptions, potential natural forces, etc.

For example, various commercial models that simulate a three-dimensional emergency release during a loss of pipeline containment are available for jet fire, flash fire, pool fire, toxic release, vapor cloud explosion (VCE), boiling liquid expanding vapor explosion (BLEVE), and an unconfined vapor cloud explosion (UVCE). These outcomes are also analyzed using source and dispersion models, explosion and fire models, as well as effects models, that determine the consequences to individuals, society, and infrastructure.

UVCE and flash fires occur when a large amount of volatile flammable material is rapidly dispersed to the atmosphere, forms a vapor cloud that disperses and meets an ignition source before the cloud is diluted below the lower flammability limit (LFL). In the event of ignition, the key concern in UVCE modeling is the shock wave that would cause significant damage to people and infrastructure. The main concern with a flash fire is the effect of thermal radiation on man, materials, and machines. The transition from a flash fire to a UVCE cloud is a function of the flammable mass, presence of confinements, burning velocity of the material, as well as other factors.

The commercial models are capable of simulating instantaneous, catastrophic, continuous, or transient releases. These models also present quantification of the release scenarios based on: the discharge rate and extent of vaporization of liquid spills/pools, gas dispersion, vapor expansion, shock wave, ignition and thermal radiation effects. Through their use the important aspects and attendant consequences of accidental loss of pipeline containment can be computed. They are capable of (a) scenario and situation modeling, (b) modeling that includes varying meteorological conditions (e.g., clear or cloudy days and nights), and (c) modeling passive transportation and dispersion of toxic substance particles.

The modeling tools can produce maps that depict critical danger zones:

- Heat exposure hazard
- Flame exposure hazard
- Overpressure hazard
- Toxicity and asphyxiation hazard

Prior to building a new pipeline these mapped zones would determine the safest proximity distances between the population and critical infrastructure and the new pipeline. The maps should also constitute a key component of evacuation plans, emergency response plans, the location of emergency isolation valves (particularly for remote locations), and emergency de-pressurizing and/or de-inventory.

Strategies such as diking, selective grading, water spray, deluge, foams, water curtain, and blast-resistant construction would benefit from prior critical hazard zone detailed mapping. The information could also be used to delineate the actions to take after a release in terms of exposure avoidance, self-confinement, or evacuation. The mapping would help to formulate spill/leakage response and flow-path diversions to prevent the product from migrating along available pathways to people, property, and environment. The placement of safety zones and critical equipment is highly relevant here. In high consequence areas, the scenario analysis with mapped impact distances would provide an estimate of men, materials, and machines that could be seriously affected.

The central role of hazard modeling in quantifying the consequences of a pipeline failure is schematically illustrated in Figure 6.4. Effective models should provide realistic estimates of the number of people at risk and projected property damage. Combined with the corporate cost estimates of line repair, lost product, and service interruption, projection modeling provides a realistic financial picture of pipeline failure. Typical consequence ratings could be:

Safety impact: number of people at risk = 0

Environmental impact: spill volume of oil = 9,000 bbls

Cost impact: financial cost = $250,000 to $300,000

Production impact: pipeline operation = Partial shutdown

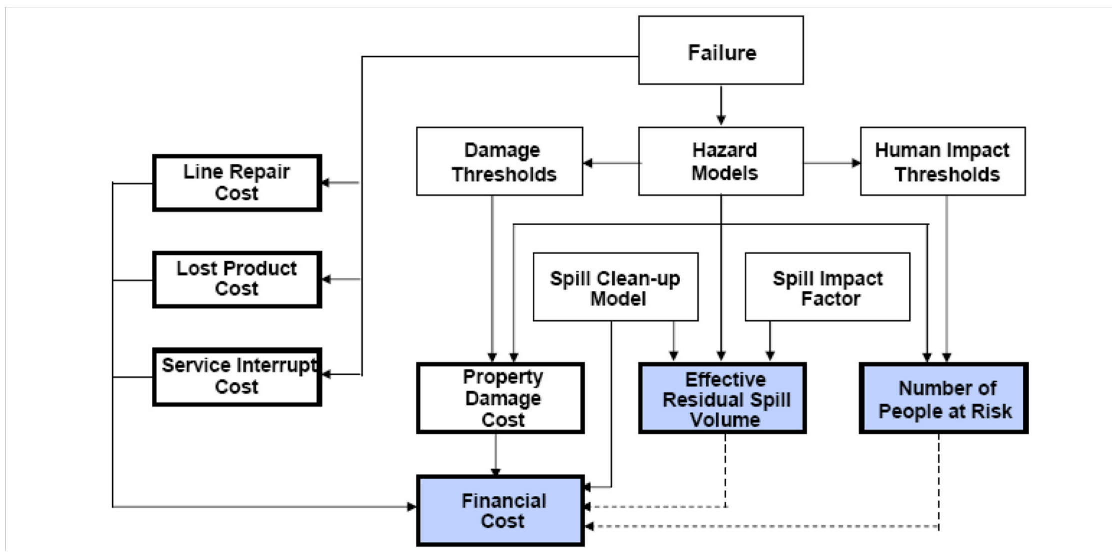


Figure 6.4 A Schematic Flow-Chart for Quantification of Consequences of Pipeline Failure

(Source:CO_2 Capture & Storage Workshop, Alberta, Canada, 2006)

Consequence analysis results would help to revise and upgrade planned risk control processes including prevention, mitigation, and response plans. Corrosion control, maintenance, and impact barrier plans may well need to be revised. These results could provide the impetus to make planned mitigation steps more robust. The need for isolation valves, dikes, trenches, sprinklers and/or deluge systems could have greater prominence because of consequence analysis results. Results from all consequence analyses could heighten recognition of the need for global code development to focus on identifying failure modes and minimizing the likelihood, frequency, and consequences of failure.

6.5 Risk Assessment: Prescriptive and Performance Based

Operators of pipelines transporting natural gas or other hazardous liquids are required to develop an integrity management program for all pipelines and related facilities. The integrity management programs established by the operator can be either prescriptive- or performance-based. A key objective of both types of programs is to fully understand and evaluate the potential threats to a pipeline system. This is accomplished by gathering, reviewing, and integrating all the data necessary to conduct a rigorous risk assessment. The ultimate goal of risk assessment is to analyze the integrity management process data to identify and prioritize pipeline/segment risks so that the pipeline operator can schedule integrity assessments and allocate necessary resources when most needed. An essential part of any risk assessment program is a thorough review of all past incidents on the pipeline segment and associated facilities. However, it is important to understand that a risk assessment model based on history is not sufficient; pipeline operating conditions change constantly.

6.5.1 Prescriptive-Based Risk Assessment

For a first-time assessment, the prescriptive-based processes are normally recommended. Here, the required data sets are well defined as illustrated in Table 6.4. This process requires the least amount of data and less rigorous overall analysis without sacrificing any aspect of the integrity process: risk assessment, inspection, prevention, detection, and mitigation.

Table 6.4: Data Elements for a Prescriptive Pipeline Integrity Program and to Initiate a Performance-based Process (ASME B31.8S-2004)

Category	Data
Attribute Data	Pipe wall thickness
	Diameter
	Seam type and joint factor

Category	Data
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
Construction	Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coating methods
	Soil, backfill
	Inspection reports
	Cathodic protection installed
	Coating type
Operational	Gas quality
	Flow rate
Operational (continued)	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP (cathodic protection) system performance
	Pipe wall temperature

Category	Data
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
Inspection	Pressure tests
	In-line inspections
	Geometry tool inspections
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

A prescriptive-based risk assessment process follows preset conditions that result in fixed inspection and mitigation activities and timelines that the operator is require to follow in order to produce the necessary results. The process relies on qualitative probability and consequence analyses to prioritize risk. Subject matter experts (SMEs) constitute the backbone of prescriptive-based risk assessment. SMEs are from the operating company or are consultants who have the expertise in specific areas of operation and the necessary technical information to exercise sound engineering judgment and experience and provide descriptive data. The relevant regulatory bodies *prescribe* the prevention, detection, mitigation actions, and timelines for periodic risk and integrity assessments. The name derives from the fact that the process depends on regulatory prescriptions.

One form of qualitative analysis used for prescriptive-based risk assessment utilizes SMEs to assign specific values ranging from 1-5 for P_i and A-E for C_i that reflect high, medium, or low *probability* and *consequence* categories to construct a risk matrix. Another type of qualitative analysis utilizes failure modes, effects, and criticality analysis (FMECA) and/or hazard and operability (HAZOP) study to assign specific P_i and C_i values for a risk matrix to prioritize each pipeline segment within the particular operation. FMECA and HAZOP, originally developed for the process industries, determine the significance of possible risk based on its criticality analysis (FMECA) and HAZOP identifies unforeseen hazards that were designed into facilities due to lack of information or were introduced into existing facilities by changes in pipeline operation.

A preeminent advantage of prescriptive-based risk assessment is the fact that it does not require large volumes of exact data, which in the real world are often out of date, missing, inaccurate, and usually difficult to find. It is an adequate substitute for an initial performance-based process as it clears the way for a semi-quantitative or quantitative assessment.

The prescriptive-based risk assessment process is consistent with the expected outcome requirements of API RP 580 (2002), the API recommended practice for developing risk-based inspection for fixed equipment and piping in the hydrocarbon and chemical process industries;

- it generates risk ranking of pipeline segments,
- its inspection plan, including inspection methods, coverage, and intervals, are well defined and detailed as depicted in Table 6.4, and
- its risk mitigation activities are well defined as depicted in Table 6.5 for time-dependent threats (internal corrosion, external corrosion, and SCC).

Table 6.5: Example Illustrating How Prescriptive-Based Approach is Consistent with the Requirements of API RP 580
(Source: Table 6 of ASME B31.8S, 2004)

Threat	Criteria/Risk Assessment	Integrity Assessment	Mitigation	Interval, Years
External Corrosion	Some external corrosion history, no in-line Inspection	Conduct hydro-static test, perform in-line inspection, or perform direct assessment	Replace/repair locations where CFP below 1.25 times the MAOP	10
Internal Corrosion	No history of IC issues, no in-line inspection	Conduct hydro-static test, perform in-line inspection, or perform direct assessment	Replace/repair locations where CFP below 1.25 times the MAOP	10
SCC	Have found SCC of near critical dimension	Conduct hydro-static test	Replace pipe at test failure locations	3-5

A strong statement in support of prescriptive-based risk assessment process is contained in the following quote from API RP 580 (2002):

"*risk presented as a precise numeric value (as in a quantitative analysis) implies a greater level of accuracy when compared to a risk matrix (as in a qualitative analysis). The implied linkage of precision and accuracy may not exist because of the element of uncertainty that is inherent with probabilities and consequences...*"

Finally, the prescriptive-based risk assessment process addresses stakeholders' needs. Management needs the risk assessment to link specific risks to appropriate inspection or mitigation activities; they need to foresee the possible decision scenarios made possible by risk assessment. Vice versa, it is important they anticipate the nature of risk assessment results needed to support a sound decision-making process.

The stakeholders must also have a clear idea of the level of commitment or resources that would be required to successfully implement a comprehensive risk assessment in particular, and integrity management in general. Because of its relative accuracy, cost and time effectiveness, the prescriptive-based approach usually has a universal acceptance by stakeholders.

6.5.2 Performance-Based Risk Assessment

A performance-based risk assessment process does not follow preset conditions. It allows the operator more freedom and greater flexibility to meet or exceed required standards; it utilizes risk management principles and assessment to determine the best prevention, detection, and mitigation actions and their timing. Table 6.4 represents the bare minimum data set that could be used for program initiation. Beyond that, additional data may be sourced as detailed in Table 6.6 including the data from prior integrity assessment processes: (1) pipeline and system information, (2) "in-line" and "over the line" inspection data, (3) failure, defect, repair and excavation information, (4) on-going maintenance programs, (5) as-built and mapping information (auto-CAD and drafting), and (6) material specifications.

Table 6.6: Typical Data Sources for Pipeline Integrity Program (ASME B31.8S-204)

Process and Instrumentation Drawings (P&ID)
Pipeline alignment drawings
Original construction inspector notes/records
Pipeline aerial photography
Facility drawings/maps
As-built drawings
Material certifications
Survey reports/drawings
Safety related condition reports
Operator standards/specifications

Industry standards/specifications
O & M procedures
Emergency response plans
Inspection records
Test reports/records
Incident reports
Compliance records
Design/engineering reports
Technical evaluations
Manufacturer equipment data

The complexity level of the method used to assign specific P_i and C_i values in prescriptive-based risk assessment depends on whether an initial or repeat integrity assessment is planned. For an initial assessment, any method, including the SME approach discussed in connection with the prescriptive-based risk assessment, could be used. Repeat assessments are based on more complex methodologies to assign specific P_i and C_i values. These complex methods could be quantitative, semi-quantitative, or combinations of both. A semi-quantitative methodology combines both quantitative and qualitative methods.

Regardless of the risk assessment approach selected, all approaches have the following common components: (a) identification of potential events or conditions that could threaten system integrity, (b) evaluation of the likelihood of failure and associated consequences, (c) risk ranking and identification of specific threats that influence the risk, (d) identification of integrity assessment options, (e) feedback loop, and (f) a sound structure that allows continuous updating.

The performance-based processes utilize far more data and far more extensive risk analyses in order to achieve higher standards of performance than the prescriptive-based processes. Pipeline operators do not normally embark on a performance-based process until sufficient number of interactive risk assessment and inspections have been performed to provide an adequate database for a data-intensive risk assessment.

6.6 Risk Assessment Models

The following are four risk assessment models generally used.

6.6.1 Subject Matter Experts (SMEs)

Subject matter experts (SMEs) are individuals who have expertise in specific areas of operation. SMEs are able to assign specific values for P_i and C_i reflecting high, medium, or low *probability* and *consequence* and to calculate the relative risk for each pipeline segment within the particular operation.

Failure Modes, Effects, and Critical Analysis (FMECA) and Hazard and Operability (HAZOP) study fall under the SME category, as these qualitative risk analyses are dependent on the background and expertise of the analysts. The two methods, FMECA and HAZOP, were originally developed for the process industries but are now used in integrity risk identification. FMECA determines the significance of possible risk based on critical analysis and HAZOP identifies unforeseen hazards that have been designed into facilities due to lack of information, or introduced into existing facilities due to changes in pipeline operation. The results of FMECA and HAZOP studies are used to assign specific P_i and C_i values and to calculate the relative risk for each pipeline segment within its particular operation.

6.6.2 Relative Assessment Models

The relative assessment models are semi-quantitative and are commercially available. This approach is based on using extensive accumulated pipeline-specific data to develop specific relative risk algorithms that incorporate the threats and associated consequences that have been problematic. The results from the model are compared with the current risk scenario to establish a relative risk rank for the ongoing integrity management decision process. This approach is far more rigorous than the SME approach even though the two approaches are based on the knowledge of the operation under consideration. The relative risk-assessment approach is used to assign specific P_i and C_i values and to calculate the relative risk for each pipeline segment within the particular operation.

6.6.3 Scenario-Based Models

This approach is based on logic models that construct event trees, decision trees, and fault trees. The model also incorporates as much detailed information about the facility design, operating practices, operating history, component reliability, possible human actions, physical progression of accidents, and potential effects on health, environment, and safety as possible. The models can generate series of failure events (e.g., loss of containment of hazardous gas or liquid). These are combined with physical models that depict the progression of the failure, including migration of hazardous materials along available pathways to people, property, and the environment. Combined, the models are used to assign specific P_i and C_i values and to calculate the relative risk for each scenario and the corresponding pipeline segment.

6.6.4 Probability Models

Rather than using comparative analysis, this approach relies strictly on acceptable risk probabilities established from data accumulated by pipeline operators. Using extensive accumulated pipeline-specific data aids the development of applicable probability algorithms that incorporate the threats and associated consequences that previously troubled the pipeline. This approach is the most complex since it considers all possible factors including: uncertainties about codes of practice for design and construction, pipeline operation and safety measures, corrosion attributes, pipeline attributes, material properties, and operating stresses. This approach is used to assign specific P_i and C_i values as well as to calculate the relative risk for each scenario and the corresponding pipeline segment.

6.6.5 Effective Risk Assessment Approach

For both prescriptive and performance based integrity management programs, whichever risk assessment approach is adopted should incorporate, in differing degrees, the following key characteristics:

Attributes – It should be logical, structured, and consistent. A knowledge-based method may be less rigorous but, to be effective it should have a structure that contains all the categories of pipeline threats under consideration.

Resources – Needed resources (man, materials, and/or machine) must be made available to implement the program.

Operating/Mitigation history – The approach must incorporate comprehensive results of previous risk assessments, the consequences and significance of previously identified and unidentified threats as well as the risk mitigation actions taken.

Predictive capability – It should correlate and integrate previous data: inspection data, examination data, evaluation data, mitigation data, etc. By use of the database, it should be able to show trends, predict potential hazards that might lead to a loss of pipeline system integrity, predict the likelihood of occurrence, and the nature and severity of consequences if those hazards occur. The program should be able to predict the overall risks of potential hazards, rank the relative risks, establish priorities for integrity assessment, as well as the mitigation measures to produce an acceptable level of residual risk.

Risk confidence – The approach should engender confidence in the risk management process.

Feedback – It should be a continuous improvement process, integrated into daily pipeline operation with an effective and efficient feedback loop. It should also be adaptable.

Documentation – The process should include thorough and complete documentation that is continuously updated to incorporate modifications, changes, and new integrity information.

Scenario analysis – The approach should provide answers to a variety of "what-if" questions about risk criteria, risk identification, risk estimation, risk analysis, risk evaluation, risk assessment, risk mitigation, residual risk, risk acceptance, and risk reduction benefit from maintenance or remedial actions.

Weighing factors – An effective risk assessment approach cannot unduly overrate or underrate the likelihood or consequence of any failure. Not all potential hazards should have identical influence on the relative risk assessment process. Realistic weighting factors should be based on internal, external, and global experience.

Structure – An effective methodology must be structured, documented, and verifiable. It should be able to compare and rank risk assessment results in a consistent manner to support the management decision process.

Dynamic segmentation – For purposes of risk assessment, the segment lengths of pipeline should be defined. The methodology should take into account the changes arising from mitigation activities that affect the character of each segment, which might require segment re-definition. Segment definition should be updated continuously incorporate modifications and changes resulting from each subsequent integrity assessment.

6.6.6 Using Risk Assessment Models

Any risk assessment approach should first be used for a trial screening that does not encompass the entire pipeline system. To be meaningful, it is best for this trial screening to focus on those segments of the pipeline with a history of failure. It is then easy to test the precision of the selected approach. An effective approach would certainly confirm what is already known. It would be a test of the model, a test of the risk assessment team, and a test of the subject matter experts, as well as managers, engineers, pipeline operations personnel, maintenance personnel, technicians and others versed in risk assessment and mitigation. After the trial run a full-blown risk assessment may then be implemented.

Following the baseline assessment, the interval chosen for the next integrity assessment should be consistent with the recommendations depicted in Table 6.7. Operators must consider many factors to establish an appropriate interval between inspections such as: the defect types and sizes detectable by the inspection method, the stress levels, the defect growth rates, and the effectiveness of actions taken to correct chronic time-dependent problems.

Table 6.7: Prescriptive Integrity Assessment Intervals (ASME B31.8S-2004) Time Dependent Threats, Prescriptive Integrity Management Plan

Time-Dependent Threats, Prescriptive Integrity Management Plan

		Criteria		
Inspection Technique	**Interval (Years) [Note (1)]**	**At or Above 50% SMYS**	**At or Above 30% up to 50% SMYS**	**Less Than 30% SMYS**
Hydrostatic Testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.4 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]	TP to 2.2 times MAOP [Note (2)]
	15	Not allowed	TP to 2.0 times MAOP [Note (2)]	TP to 2.8 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.3 times MAOP [Note (2)]
In-line inspection	5	P_f above 1.25 times MAOP [Note (3)]	P_f above 1.4 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]
	10	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]	P_f above 2.2 times MAOP [Note (3)]
	15	Not allowed	P_f above 2.0 times MAOP [Note (3)]	P_f above 2.8 times MAOP [Note (3)]
	20	Not allowed	Not allowed	P_f above 3.3 times MAOP [Note (3)]
Direct assessment	5	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	10	All indications examined	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	15	Not allowed	All indications examined	All indications examined
	20	Not allowed	Not allowed	All indications examined

NOTES:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.

(2) TP is Test Pressure

(3) Pf is predicted failure pressure as determined from ASME B31G or equivalent.

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for reinspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% of SMYS.

6.7 Calculating and Quantifying Risk

When probability and consequence are expressed numerically, risk is the product:

Risk = Probability x *Consequences*

The risk of a specific consequence is therefore given as:

Risk of a specific consequence = (Probability of the specific consequence) x *(Consequences of the specific consequence)*

Risk estimation combines the likelihood and consequences of all incident outcomes from all selected incidents to establish the total measure of risk. The risks of all selected incidents are individually estimated and summed; the sensitivity and uncertainty of each risk estimate are factored into the summation of total risk. If, for example, the specific consequence is fire, then it is necessary to calculate the probability of fire and the consequence of fire in order to be able to estimate the risk of fire. The required equations are as follows:

Probability of a fire = (Probability of pipeline failure) x *(probability of rupture)* x *(Probability of ignition)* x *(probability of fire upon ignition)*

Ignition as used in this equation is similar, but not identical, to its use in an internal combustion engine. Most ignitions lead to fire; but a non-negligible percentage of ignitions do fizzle out.

Risk of fire = (Probability of a fire) x *(Consequences of fire)*

For illustration purposes, the probability of pipeline failure (P_c) of *the 40-mile natural gas pipeline* in Example 7.1 is *0.004.* According to the Federal Emergency Management Agency (FEMA), when a gas pipeline fails, the various probabilities associated with the probability of fire are as follows:

Probability of leak = 0.8

Probability of rupture = 0.2

Probability of ignition = 0.3

Probability of fire upon ignition = 0.7

Therefore, using the required equations given above, the probability of fire is as follows:

Probability of a leak fire = $(0.004) \times (0.8) \times (0.3) \times (0.7) = 0.000672$

or 6.73×10^{-4}

Probability of a rupture fire = $(0.004) \times (0.2) \times (0.3) \times (0.7) = 0.000168$

or 1.68×10^{-4}

If the consequence of fire for Example 7.1 had been assessed as one million U.S. dollars, the risk of fire could be calculated as follows:

Risk of leak fire = (Probability of a leak fire) x *(Consequences of fire)*

Risk of leak fire = $(6.73 \times 10^{-4}) \times (\$1 \times 10^6) = \$673$ *per year*

Risk of rupture fire = (Probability of a rupture fire) x *(Consequences of fire)*

Risk of rupture fire = $(1.68 \times 10^{-4}) \times (\$1 \times 10^6) = \$168$ *per year*

In principle, therefore, one could calculate the risk for reactions caused by failure of a natural gas pipeline: jet fire, flash fire, pool fire, vapor cloud explosion (VCE), boiling liquid expanding vapor explosion (BLEVE) and unconfined vapor cloud explosion (UVCE). The summation of these risks is the risk due to fire and explosion:

$$Risk_{(fire\ \&Explosion)} = R_{jet\ fire} + R_{flash\ fire} + R_{pool\ fire} + R_{VCE} + R_{BLEVE} + R_{UVCE}$$

6.7.1 Relative Risk

According to API 580 (2002), relative risk is the comparative risk of one facility, process unit, system, equipment item, or component to other facilities, process units, systems, equipment items, or components, respectively. Establishing relative risk is pivotal; you must conduct a comparative risk analysis between two different pipelines/segments in order to establish differentiation data. That data is essential to set the priorities necessary for integrity assessment. Risk-based inspection (RBI) is focused on a systematic determination of relative risks.

Qualitative, semi-quantitative, and quantitative approaches are all suitable to establish relative risk ranking. If probability and consequence are qualitative, a risk matrix should be used for relative risk ranking as depicted in Figure 4.5 of Chapter 4; this figure plots the *probability of a specific consequence* against the *specific consequence*. Pipeline segments that fall in the higher risk category should have the highest priority to receive mitigation to lower residual risk to the lower risk ranking.

Relative risk ranking can also be established either by consequence analysis alone or probability of failure analysis alone. Inspection engineers do not normally have much control over consequence of failure, therefore they use probability of failure rather than establish a relative risk ranking for inspection and maintenance planning. This is the primary focus of risk-based inspection (RBI), which uses inspection to reduce uncertainty and increase predictability of pipeline deterioration. Maintenance personnel can then carry out repair and/or replacement prior to a "predicted" failure date. Conversely, management and process safety personnel do not normally have much control over the probability of failure so they use the consequence of failure to establish a relative risk ranking thus reducing the consequences of failure by operational process modifications for integrity failures such as brittle fracture, high-cycle fatigue, etc.

It is possible that the principles of high consequence areas (HCA) have skewed integrity management toward using probability of failure rather than establishing a relative risk ranking. High consequence areas include populated areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. Anything that threatens integrity increases failure probability and any failure in an HCA will be more serious than a similar failure in a non-HCA region. Hence, any HCA segment with a high probability of failure has a higher relative risk than a non-HCA segment with a similarly high probability of failure. HCAs (as previously noted) are defined relative to a distance within and/or beyond 660 feet (200 meters) from the centerline of a pipeline.

6.7.2 Absolute Risk

Absolute risk computation implies knowledge of absolute failure probability and absolute consequence of failure. But calculating absolute risk is essentially impossible because of the many uncertainties associated with data and the many variables associated with loss of containment. A "bullet-proof" pipeline-modeling tool that could guarantee virtually no chance of failure does not yet exist. Nonetheless, true risk calculation is the key to making good mitigation decisions and to risk acceptance, and is substantially more valuable in developing risk response strategies. Absolute risk targets require absolute quantitative risk estimates.

Perhaps, the strongest statement against absolute risk is contained in the following quote from API RP 580 (2002):

"risk presented as a precise numeric value (as in a quantitative analysis) implies a greater level of accuracy when compared to a risk matrix (as in a qualitative analysis). The implied linkage of precision and accuracy may not exist because of the element of uncertainty that is inherent with probabilities and consequences... In practice, there are often many extraneous factors that will affect the estimate of damage rate (probability) as well as the magnitude of failure (consequence) that cannot be fully taken into account with fixed model..."

Indeed, qualitative approaches may be misleading if the numbers give the appearance of precision and specificity. In spite of this, qualitative analysis conducted rigorously enough, can yield results that could approximate absolute risk. Numeric risk values derived from semi-quantitative, qualitative, and sensitivity analysis might also approximate absolute risk. It is crucial to start with a simplified level of detail and only increase the complexity if the established target is not met and if it is clear the cause is either simplification or conservative judgments in the analysis. Because it is so difficult to compute absolute risk, what is done instead is to establish a maximum release frequency or a maximum number of potential consequences.

If probability and consequence are quantitative, a risk plot is used for relative risk ranking as shown in Figure 6.5, which is a log-log plot of the *probability of a specific consequence* against the *specific consequence*.

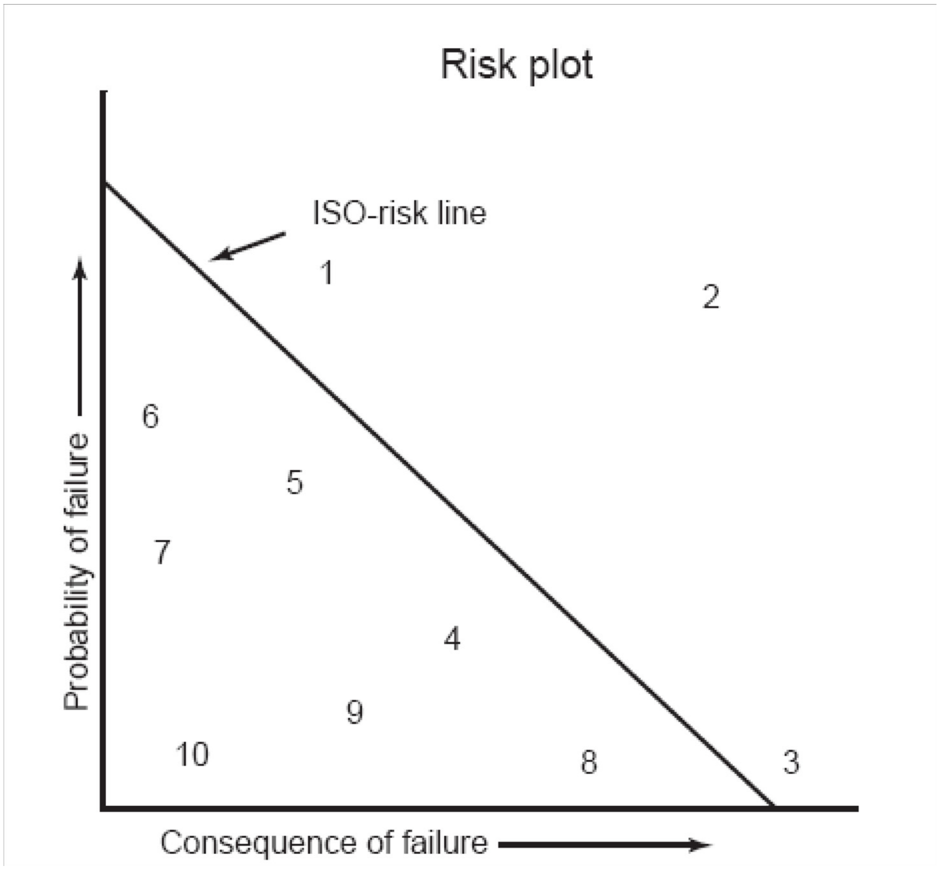


Figure 6.5 Risk Plot When Using Quantitative Risk Values
(Source: API RP 580; 2002)

Pipeline segments that fall to the right of ISO risk line (line of constant risk) have the highest priority to receive residual risk mitigation and thus fall to the left of the ISO-risk line. This is the case for items 1, 2, and 3 on Figure 6.5.

What risk value is acceptable or unacceptable? This is the crux of the absolute risk question. The answer provides some clues to how the ISO-risk line is determined. If for example, the risk of a person becoming a casualty of a pipeline failure is unacceptable, then such a level of absolute risk is too high and cannot be tolerated under any circumstances. All necessary pre-emptive and/or mitigative actions must be taken to ensure that the absolute risk associated with such an eventuality is minimized to the level where a casualty is not an option. This then defines the ISO-risk line, below which risk is tolerable. If, however, it is acceptable that a spill as a result of a pipeline failure occurs, then the level of absolute risk is low and no pre-emptive and/or mitigation action needs to be taken. This risk is negligible, in principle, and the case history below illustrates the point succinctly.

Much like corrosion, risk is an unpleasant fact of life. Risk cannot be eliminated; it can only be controlled "As Low As Reasonably Practicable" (ALARP). The ALARP concept is particularly relevant for risk mitigation and risk acceptance. The "Low" refers to the effectiveness of the mitigation processes and the "Practicable" refers to efficiency. It entails the comparison of the estimated risk against the given risk or risk targets (ISO-risk line) to establish the significance of the identified risk. The mitigation process that achieves the greatest risk reduction for a pipeline segment at the optimal cost is the desired mitigation action.

As illustrated in Figure 6.6, the ALARP principle comes to the rescue when the risk associated with a pipeline failure is somewhere between the acceptable and the unacceptable.

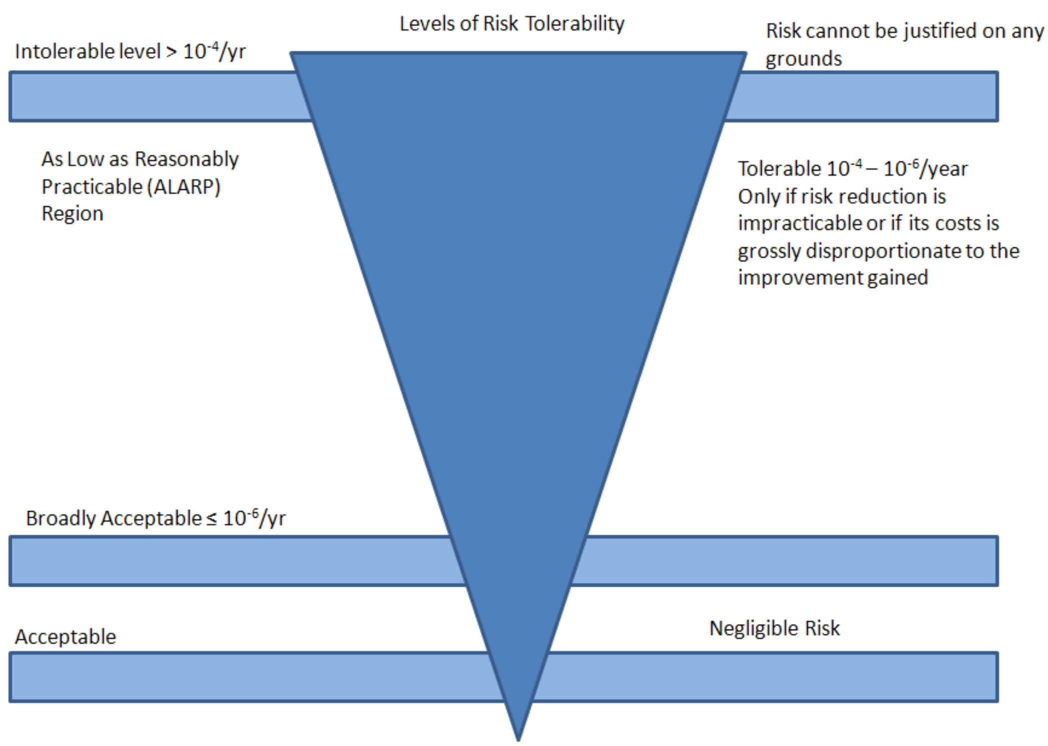


Figure 6.6 Principle of "As Low As Reasonably Practicable" (ALARP)
(Source: Pigging Products and Services Association, 2004)

If the proposed 40-mile natural gas pipeline with a 1.68×10^{-4} probability of fire has a consequence of 0.2 for people being injured, then

$$Risk\ of\ injury = 0.2 \times 1.68 \times 10^{-4}$$

$$Risk\ of\ injury = 3.36 \times 10^{-5}\ per\ year$$

Therefore, the risk of injuries falls below the intolerable range 10^{-4} and above the broadly acceptable range of 10^{-6}. This risk level is tolerable only if risk mitigation is not practicable or if the cost of the risk reduction is grossly disproportionate to the improvement gained. After the mitigation activities for a pipeline system, the estimated risk equals the residual risk of the pipeline operation. Thus, the ALARP principle provides an essential learning curve for living with risk.

Case Study

Pipeline risk analysis of a 12-inch (30.48 cm) diameter natural gas pipeline, located at the Highgrove Facility near proposed Colton High School Site No. 3, Grand Terrace, San Bernardino County, California (August 2005).

The high-pressure natural gas pipeline is a 12-inch (30.48 cm) diameter distribution line that would serve the Highgrove Site (HG) across Taylor Street. The closest approach of the line to the site would be 510 feet (155.45 m) on the west, which would be about 1,560 feet (475.49 m) northwest of the site building mass center point. About 2,530 feet (771.15 m) of the pipeline would be located within 1,500 feet (457.2 m) of the site boundaries and 1,520 feet (463.3 m) within 1,500 feet (457.2 m) of the site center point. Pipeline maximum operating pressure is proposed to be 560 psig, within an expected average operating pressure of 300 to 450 psig. It is anticipated that the pipeline would be buried at a depth of 42 to 60 inches (106.6 c to 152.4 c) and pipeline construction is anticipated to occur in 2007-2008, and it would be constructed of modern materials. It is anticipated that the gas flow could be shut down within 30 minutes of an incident.

The failure probability for 12-inch (30.48 c) distribution pipeline was calculated to be 2.8×10^{-4} per mile.

The length of pipe within the 1,500 feet (457.2 m) of the site is 940 feet (286.5 m).

Hence the annual failure probability is $(2.8 \times 10^{-4}) * (940 \text{ feet} / 1 \text{ mile}) = 2.8 \times 10^{-4} * 0.178$

Hence the annual failure probability is 4.98×10^{-5}.

The consequence analysis involved the estimation of overpressure and heat flux impact. The individual risk and all societal risks were determined to be **insignificant**. Hence the risk outcome is considered **insignificant**.

In the unlikely event of an incident, it was pointed out that three fire stations are within approximately 3.5 miles (4.82 k) of the site. With regard to third-party digging, backhoe, drill dig, and trench excavators, current law requires them to contact Underground Service Alert (USA) at least 48 hours prior to the planned start of an excavation. Pipeline warning markers will also be installed within 1,500 feet (457.2 m) of the school site boundaries to further decrease the probability of accidental “dig-in” type accidents near the school. A “Safe shutdown” valve will be considered at the point where the 12 inch (30.48 c) diameter pipeline enters the campus to minimize releases that could result from any unforeseen seismic event or accident.

6.8 Risk Minimization through Corrosion Control

As evident from the discussion so far, corrosion control and management are practically synonymous with pipeline risk control and management. Pipeline risk management is a process designed to identify potential events that might negatively affect pipeline integrity. It also functions to ensure risk is within management’s targeted risk tolerance level and that ALARP goals are reached via the numerous risk control activities and measures available.

The three fundamental elements of risk management are: (1) the risk-assessment process; (2) the risk-control process; and (3) performance-monitoring. A brief summary of the fundamentals of risk assessment (discussed in the previous sections) are shown in Table 6.8. Examples of corresponding performance measures linked to the three stages of a pipeline incident are presented in Table 6.9.

Table 6.8: Risk Control Activity Progression of a Pipeline Incident

Prevention	Mitigation	Appropriate Response
Corrosion Control	Isolation Valves	Evacuation
Maintenance Programs	Dike/Trench	Spill Response
Impact Barrier	Sprinkler/Deluge	Flowpath Diversion

Table 6.9: Performance Measures Associated with Stages of a Pipeline Incident

Preventing the Cause	Mitigation	Appropriate Response
Hydrotest results	Isolation Valve Reliability	Emergency Drill Effectiveness

In order to reduce risk, it is clearly essential to identify the risk control issues and options and to compare them. These two steps enable you to select the best set of design and operational practices to produce the greatest degree of safety. To know if the decisions you have implemented yield the intended results you must: select performance measures, track actual performance, and adjust the process to ensure the greatest safety.

As described in Chapter 2, corrosion control methods are often used in conjunction with each other to benefit from synergy. For example, protective coatings are used to minimize the current requirements in cathodic protection; zinc metal, a CP sacrificial anode, is used as a pigment in protective coatings; passivating inhibitors are used with corrosion resistant alloys; and intelligent/scraper pigging is periodically used in lines that are chemically treated to control internal pipeline environments. When methods are combined this way, you can achieve much better results. However, when a pipeline corrosion control system is ineffective or non-existent, there is a high likelihood that its integrity will be compromised and result in a pipeline incident.

Corrosion control is fundamental to good pipeline corrosion-integrity management. Examples of additional corrosion risk-minimization methods are:

- More frequent inspection of rectifiers, test points, and detail surveys;
- Using in-line inspection and advanced internal corrosion mitigation and monitoring techniques to reduce the potential risk of a pipeline rupture resulting from corrosion;
- Applying comprehensive risk management techniques to evaluate and mitigate problems with tape coatings on large diameter pipelines;
- Evaluating shorted casing corrosion, over pressure protection, and proof testing of new or existing pipelines that use inert gas along with techniques to minimize and identify corrosion;
- Modified corrosion inspection test intervals;
- Exploiting risk-reduction benefits of new corrosion control technologies; and
- Use enhanced data collection and analysis tools to support corrosion risk management.

6.9 Integrity Verification

6.9.1 Definition

Verification is "the act of reviewing, inspecting, testing, checking, auditing, or otherwise establishing and documenting whether items, processes, services, or documents conform to specified requirements." According to ISO 9000:2000, verification is defined as the "confirmation, through the provision of objective evidence, that specified requirements have been fulfilled". Perhaps the simplest definition of verification is the act of providing "additional proof that something that was believed is true."

What does this mean in relation to pipeline integrity?

Pipeline codes offer such excellent guidelines and parameters that new pipeline systems are built with excellent design, meticulous material selection, and a strong construction philosophy. Because of this, a new pipeline system is generally sound, and in compliance with the applicable regulations/standards governing design, operation, and maintenance. For these reasons, new pipelines perform safely.

But for how long? In time the pipeline material will begin to deteriorate from corrosion reaction to its environment. Corrosion is a material property; the energy released when a metal converts to corrosion products is the driving force for its own corrosion. That is, corrosion cannot be stopped. What then about the pipeline systems built many years ago?

To forestall possible catastrophic ruptures of high-pressure transmission pipelines, pipeline operators are required to determine if their pipelines can continue to operate at the originally established maximum operating pressure allowable. Operators must perform inspections to identify time-dependent defects which could compromise the continued safe operation of the pipeline system. They have a mandate to periodically provide “additional proof” that the pipeline system is still sound.

This defines “verification” in pipeline corrosion integrity management.

6.9.2 Overview of Integrity Verification Objectives

Pipeline integrity was the recurring issue in several catastrophic ruptures of high-pressure transmission pipelines, examples of which are illustrated in Table 6.10.

When pipeline integrity is compromised, the probability of leaks or spills is high. Oil or gas leaks have a deleterious impact on health, safety, environment, and the economy. It is the recognition of the societal impact that has significantly elevated focus on pipeline integrity. Health, safety and environmental (HSE) concerns now drive government regulations globally. Therefore, the “verification” is at the root of pipeline integrity management. Public safety and environmental concerns fuel the need to maintain pipeline infrastructure; government and industry standards provide the measuring sticks for compliance.

Table 6.10: Pipeline Ruptures Caused by Corrosion

	Year of Rupture	Transmission Pipeline	Location
1	1960	Natural gas	Natchitoches, Louisiana[1]
2	1985	Natural gas	Trans Canada Pipeline
3	1985	Natural gas	Beaumont, Kentucky[2]
4	1986	Natural gas	Lancaster, Kentucky[2]
5	1986	Gasoline	Mounds View, Minnesota[3]
6	1988	Natural gas	Kansas[4]
7	1996	Fuel Oil	Fork Shoals, S. Carolina[5]
8	1996	Gasoline	Gramercy, Louisiana[6]
9	1996	Liquid Butane	Lively, Texas[7]
10	1999	Gasoline	Bellingham, Washington
11	2000	Natural gas	Carlsbad, New Mexico
12	2003	Gasoline	Tucson, Arizona

1R.R. Fessler, "Stress-Corrosion-Cracking:, in Proceedings from the Fourth Symposium on Line Pipe Research, PRCI.L30075, F1-F18

2National Transportation Safety Board. "Texas Eastern Gas Pipelines Company Ruptures and Fires at Beaumont, Kentucky, on April 27, 1985 and Lancaster, Kentucky, on February 21, 1986, Pipeline Accident Report NTSB/PAR87/01 (Washington, DC: National Transportation Safety Board, 1987).

3National Transportation Safety Board, Williams Pipe Line Company Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986,"Pipeline Accident Report NTSB/PAR-87/02 (Washington, DC: National Transportation Safety Board, 1987).

4National Transportation Safety Board, Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988*, to March 29, 1989,* Pipeline Accident Report NTSB/PAR-90/03, (Washington, DC: National Transportation Safety Board 1990).

Table 6.10: (Continued)Pipeline Ruptures Caused by Corrosion

	Year of Rupture	Transmission Pipeline	Location

5National Transportation Safety Board, "Pipeline Rupture and Release of Fuel Oil into the Reedy River at Foak Shoals", South Carolina, June 26, 1996, Pipeline Accident Report NTSB/PAR-98/01., (Washington, DC: National Transportation Safety Board 1990).

6National Transportation Safety Board, Pipeline Accident Brief DCA96MP004, 1996.

7National Transportation Safety Board, "Pipeline Rupture, Liquid Butane Release, and Fire, Lively, Texas August 24, 1996", Pipeline Accident Summary Report NTSB/PAR-98/02/SUM., (Washington, DC: National Transportation Safety Board, 1998)

The key regulations include the following:

- Potential impact zones of pipeline segments should be delineated.
- In particular, time-dependent threats (including the attendant risk assessments for each pipeline segment) should be documented. Minimizing environmental and safety risks should be the guiding principle. (Time-dependent threats relate to internal corrosion, external corrosion, and stress corrosion cracking.)
- A baseline assessment plan identifying all threats, the chosen integrity assessment method, and the schedule for all pipeline systems, should be developed and documented. In addition, direct assessment plans should be documented particularly for pipelines that cannot be pigged or subjected to hydrostatic testing or are not designed to be inspected by ILI tools. (Emerging practice dictates that intelligent pigging of new pipeline systems should be carried out within one year of commissioning in order to obtain baseline data.)
- Develop comprehensive documentation for mitigation plans, remediation plans, prevention plans, continual inspections, evaluation and assessment.
- Data should be gathered, reviewed, integrated, and updated on a regular basis. Documentation should be available for each process step including prevention and/or mitigation measures.

- Periodic risk reassessment should be integral to the system.

Inspection is the key to verification. The main focus is to detect the earliest signs of internal corrosion, external corrosion and/or stress corrosion cracking. Early detection is crucial to corrosion risk assessment, helps to ensure reliability of production and helps eliminate or minimize losses from operation disruptions. Verification factors include the results of previous inspections (if any), the pipeline's leak history, material and coating conditions, cathodic protection history, the type of pipe seams used, the products transported, and the operating pipe stress levels.

Company records, operating procedures, design criteria, and personnel are the logical starting points for total inspection programs. To maintain the schedule and budget, it is essential that prior to the kick-off at the verification process, project procedures for each item such as inspection, line cleaning, general operations, and safety be established. For example, pigging procedures and a decision flow chart minimize the risk of pigs becoming lodged in the pipeline.

The "in field" phase of the verification will generate a significant amount of data that must be verified prior to implementing remediation or mitigating measures. For this reason, the verification data should be stored in a GIS (Geographic Information System) database format incorporated into a GPS (Global Position Surveying) system. GIS facilitates a graphic viewpoint of a pipeline system; it moves easily from high-level overviews to specific details. GPS enables pipeline data to be field captured and simultaneously mapped with a high degree of accuracy. The integrated GIS/GPS approach provides unlimited potential for growth of data analysis, field comparisons, and data evaluation processes. It captures integrity data and geo-reference data in one-step. It supports consistent data formatting, integrity analysis and primary risk assessment. It also enables the update of positional information directly from the database and future tie-ins to corporate databases.

6.9.3 Overview of Integrity Verification Tools

Pipeline program standards require continual assessment, evaluation, correction, and validation of pipeline integrity. Once the pipeline has been evaluated and its historical records reviewed, it should be analyzed to verify that the integrity of the system is adequate. New pipeline systems should also schedule integrity verification. There are three main tools used in pipeline integrity verification.

- In-Line Inspection
- Hydrostatic or Pressure Testing
- Direct Assessment

6.9.3.1 In-Line Inspection (ILI) Tools

Pipeline operators began to use a form of instrumented inspection technology in the mid 1960s. This has now evolved into what is known today as In-Line Inspection (ILI) often referred to as “intelligent” or “smart pigging.” ILI tools may be either free swimming (propelled through the pipeline by the pipeline product), tethered (pulled through sections of pipeline) or robotic/crawler (currently under development). They use non-destructive inspection techniques to inspect the pipeline from the inside out. ILI systems collect and record data as they move through the pipeline from as many as 4,000 on-board sensors. Data collected by ILI tools are then processed and analyzed by the ILI vendor. The ILI data is usually provided in hard copy reports or in electronic data files viewed within the ILI vendor’s proprietary software. Table 2.8 in Chapter 2 presents the inspection purposes, anomaly types, and ILI tools to detect all the 21 threats to pipeline integrity (see ASME B31.8S). Figure 6.7 contains pictures of some ILI tools.

The principal advantages of ILI tools are: (1) applicability to long sections of pipeline, (2) ability to retrieve and compare previously logged data for corrosion trending, (3) transferability of data to geographic information system (GIS) and, (4) the non-destructive nature of the tools. Compared to hydrostatic testing, there are two main advantages of ILI tools: (1) ILI tools typically do not require taking the pipeline out of service, (2) they can detect small and large defects in a pipe. Some disadvantages include: (1) ILI does not detect coating anomalies or areas of inadequate CP, AC or DC interference. The ILI process may require many types of ILI tools for geometry (i.e., metal loss, etc.) to make a single pipeline assessment; (2) pipelines not designed for the ILI process may require extensive and costly modifications. ILI tools require certain operating parameters and limitations that must be met by the pipeline operator in order to collect quality data and avoid damage to the tools themselves.

Figure 6.7 In-Line Inspection Technologies

Not only do ILI tools provide information about the anomalies they are designed to detect, they also provide information about other pipeline attributes and features. The features usually detected include: girth welds, joint length, valves, flanges, taps, tees, wall thickness changes, and wall thickness transitions. Other features that ILI can detect include: casings, metal in close proximity, hard spots, laminations, manufacturing seams, clamps, repairs, other pipeline attachments, mid wall defects and mechanical damage. ILI has now become so reliable that it is a key technology for pipeline integrity assessment worldwide. NACE Standard SP0102, "In-Line Inspection of Pipelines," outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project. Guidelines pertaining to ILI data management and data analysis are included. An essential companion guide to this standard is NACE Publication 35100.

The four primary categories of ILI technology are metal loss, crack detection, caliper/deformation, and mapping.

6.9.3.2 Metal Loss Tools

The magnetic flux leakage (MFL) method and the ultrasonic testing (UT) method are the two principal methods used for detection of metal loss in pipe walls. MFL was the first method developed and remains the most widely used. Compared to MFL, UT provides a more direct measurement of pipe body wall loss and/or body wall gain. However, it requires a liquid coupling (oil, water, etc.) between the ultrasonic transducers and the pipe wall. Both technologies support the use of defect assessment algorithms and pressure based calculations.

6.9.3.3 Crack Detection Tools

The principal methods for detecting crack-like anomalies in the pipe wall are: (1) UT shear wave, (2) circumferential or transverse MFL, and (3) electromagnetic acoustic transmission (EMAT), which is currently under development.

Crack detection tools can detect both axial (longitudinal) and circumferential (radial) cracks, externally and internally. They also detect mid-wall cracks (laminations). Crack detection tools can classify the depth of crack, size defects, and determine the width of defect colonies. Ultrasonic crack detection tools typically provide a higher probability of detection and better defect characterization than circumferential or transverse MFL technologies. Because the circumferential MFL tools do not require liquid coupling, they are used in gas pipelines. EMAT does not require a liquid coupling either, but is currently under development and was only recently introduced into the ILI tool market.

6.9.3.4 Geometry / Deformation Tools

The technology employed for the detection and measurement of dents, ovalities, wall thickness changes and bends in pipelines are primarily mechanical, although some of the techniques employ ultrasonic and eddy current technologies. Various resolution and tool configurations allow pipeline operators numerous options and cost/benefits ratios.

6.9.3.5 Mapping / INS Tools

Mapping tool technology employs the use of sophisticated inertial measurement units (IMU) as they navigate their way through the pipeline. The data collected includes angular and velocity changes in the X, Y and Z coordinates. Mapping tools are typically run in conjunction or in combination with other ILI technologies and the mapping data collected is usually integrated with other data sets for the purposes of providing an accurate X, Y and Z spatial address for all pipeline related features and anomalies. Pipeline movement (geo- technical) for example, can be measured with subsequent runs allowing pipe strain calculations to be generated. This enables the integration of other integrity and geographical data sets, superimposing them onto aerial satellite imagery.

6.9.3.6 Combination Tools

As pipeline operators are required to address all pipeline related integrity threats, ILI vendors have developed combinations of technologies in an effort to provide cost effectiveness. Some examples include UT wall thickness combined with UT crack detection and metal loss with geometry/mapping. Internal and external discrimination of metal loss anomalies is another example of a combined technology. Various other combinations exist and are possible depending on the pipeline operator's requirements.

6.9.4 Other ILI Technologies, Concepts, and Research

The development of specialized tools and new or improved technologies continues. Research and development efforts are accelerating within industry, government, and universities. Existing technologies, including MFL, UT, EMAT, eddy current and guided wave, are being improved. New concepts utilizing robotics and crawlers are being introduced for previously un-piggable pipelines. Advances are being made in sensor design, such as mechanical damage and plastic strain, for better characterization of anomalies. As an example of emerging technology, EMAT for crack detection are in field trials. This would preclude the need to batch a UT crack detection tool in liquid for gas pipelines. Multi-diameter ILI tools are also available for negotiating pipelines containing two or three pipe diameters or reduced port valves. Variable speed ILI tools are available that enable pipeline operators to maintain higher flow rates than previously allowed.

6.9.5 Pressure Testing

Pressure Testing (PT), illustrated in Figure 6.8, is an important integrity verification method. When used for pipeline testing, hydrocarbons are removed and the pipeline is completely filled with water. Hydrostatic pressure is increased until the required pressure is achieved. The required pressure is held for a period while the pipeline is visually inspected for leaks. Testing is mandated to be performed at 125% of the maximum operating pressure (MOP) for at least four continuous hours and an additional four hours at a pressure at least 110% MOP if the piping is not visible. The use of hydrotesting for integrity verification purposes is based on the supposition that, after defects that fail above MOP are removed, the line is safe to operate at MOP and below.

A special type of pressure test, a spike test, is used to detect stress corrosion cracking. During a spike test, the pipeline is maintained at the elevated pressure for a short period to induce stress corrosion cracking. If failure occurs, the pipeline is replaced. If failure does not occur, the elevated pressure imparts surface compressive stresses on the pipe, providing an important stress corrosion cracking control mechanism.

When pressure testing is used as a verification method, the tests are conducted on a specific frequency schedule for the life of the pipeline, or until an alternative verification method is selected. Water is preferred as the pressure medium to limit safety hazards and environmental damage in the event of a leak or rupture while testing. After hydrotesting, the pipeline should be emptied safely according to the appropriate regulations. The pipeline is then dried to ensure it is free of all moisture before service is resumed. Some companies run a biocide slug between two sealing pigs to lay a film on the inner surface of the pipe wall to reduce the risk of microbiologically influenced corrosion (MIC).

Pressure testing has a few significant disadvantages for pipeline operations. First, it is a destructive test. Second, it requires an interruption in service, which can be a problem when a single pipeline is feeding a plant or a whole city. It is a pass or fail test; its integrity conclusions are relevant only at the time of the test. For example, the size of the anomalies that remain can be very large and no information is provided regarding non-critical flaws that might soon become critical cracks. In the event of a failure, the cost of repairing a rupture due to a defect on the pipeline can be substantially more than the cost of repairing a defect if it were discovered through non-destructive verification. De-watering, cleaning, and drying a pipeline after hydrostatic testing are both time consuming and costly.

Figure 6.8 Hydrotesting INGAA

6.9.6 Direct Assessment (DA)

For pipelines where in-line inspection and hydrostatic verification techniques are not viable, direct assessment (DA) is a viable alternative. DA is not invasive and does not interfere with operations. It is used to identify three distinct integrity issues — external corrosion, internal corrosion and stress corrosion cracking. In the pipeline industry, the processes are referred to as follows:

- External Corrosion Direct Assessment – ECDA
- Internal Corrosion Direct Assessment – ICDA
- Stress Corrosion Cracking Direct Assessment – SCCDA

Each is a four-step process: Pre-Assessment, Indirect Inspection, Direct Examination, and Post Assessment. Each of the steps is uniquely different for the three integrity issues. Overall, DA requires effective data collection and management as well as a commitment to validation. Operators must choose the best tools to achieve pipeline reliability, safety, and asset preservation. In order to perform DA, risk data must be used to identify potential threats.

6.9.7 External Corrosion Direct Assessment (ECDA)

ECDA, as described in NACE SP0502, is a proactive structured process to improve pipeline safety by assessing and reducing the impact of external corrosion. It is a cost-effective integrity management complement, and sometimes an alternative to the in-line inspection (ILI) technique and hydrostatic testing. This is because many transmission pipelines are not "piggable;" also, many practical factors impede the use of hydrostatic testing.

ECDA is primarily concerned with the presence of holidays and other anomalies of the external pipeline coating. The key assumption is that examining the pipeline at these coatings-effected locations highlights areas where pipeline external corrosion may have occurred, is occurring, or will occur. ECDA determines CP effectiveness and compliance, AC/DC interference, electrical/geologic current shielding, current attenuation, foreign contacts, and extent of mitigation requirements. The key reference for ECDA is NACE SP0502 "Pipeline External Corrosion Direct Assessment Methodology."

The four steps for performing ECDA are:

Pre-Assessment — Pre-assessment is used to analyze the risks in terms of: environment, age, CP records, and material type, etc. The risk factor data is used to determine if ECDA is a feasible method to examine the pipeline. Pre-assessment also identifies high consequence areas (HCA). The appropriate indirect inspection tools are determined, along with the complementary or secondary indirect inspection tools. More stringent testing is required on pipelines that have not been previously tested.

Indirect Inspection — This involves analyzing raw data from such approved Indirect Inspection surveys as the close interval survey (CIS), direct current voltage gradient (DCVG), AC current attenuation (ACCA), alternating current voltage gradient (ACVG), as well as soil resistivity/chemistry surveys. Indirect inspection locates areas where coating damage may exist, and evaluates whether corrosion is occurring.

Direct Examination — Direct examination involves digging up the pipeline to confirm the accuracy of the indirect inspections. This step determines the need for repair, evaluates the likely corrosion growth rate, supports adjustments to the scope of the excavation, and evaluates the need for other technology. Indications are categorized during direct examination as (1) Immediate Action Required, (2) Schedule for Action Required, and (3) Suitable for Monitoring. Coating and corrosion anomalies are characterized and root cause analysis performed.

Post Assessment — During post-assessment, re-inspection intervals are determined, the ECDA process is validated and the remaining life is determined. A 16 mil per year (mpy) corrosion rate is used as the default corrosion rate unless the data supports another rate.

6.9.8 Internal Corrosion Direct Assessment (ICDA)

According to NACE SP0206, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas, the primary purpose of Dry Gas ICDA (DG-ICDA) is to enhance the assessment of internal corrosion in natural gas pipelines and to ensure pipeline integrity. DG-ICDA was developed for natural gas pipelines that normally carry dry gas, but may experience infrequent, short-term water upsets and accumulation. Because of this, DG-ICDA is not applicable to wet-gathering and producing pipelines. DG-ICDA includes the following four steps:

Pre-Assessment — During this process, essential historical and current operating data are collected. DG-ICDA regions are defined and all available records are collected and analyzed. Essential data gathered and used for DG-ICDA include coatings, operating history, defined length, elevation profile, features with inclination, diameter and wall thickness, pressure, flow rate, temperature, water vapor, inputs/outputs, corrosion inhibitor, upsets, type of dehydration, hydrotest information, repair or maintenance data, leaks or failure data, gas quality, corrosion monitoring, and other internal corrosion data. Pre-assessment step identifies high consequence areas (HCA). Risk factor data is used to determine if DG-ICDA is a feasible method to examine the pipeline.

Indirect Inspection — During indirect inspection of DG-ICDA, a pipeline elevation profile is developed, multiphase flow predictions are made, and likely sites of internal corrosion are identified. The specific focus of DG-ICDA is accumulation of water in the pipeline. The key assumption is that the examination of the pipeline at locations where water might accumulate provides data that describe the condition of the line downstream. DG-ICDA indirect inspection uses flow modeling to identify locations where liquid is likely to accumulate which corresponds to the locations where internal corrosion is likely to occur. The model for predicting corrosion susceptibility is based on gas composition, water chemistry, bacteria, and fluid velocity. These corrosion rate-determining factors act independently. The predicted susceptible locations are then subjected to direct examination.

Direct Examination — During this phase, several locations are excavated and detailed examinations are made of the pipe to determine whether metal loss has occurred using ultrasonic and radiographic inspection. If corrosion is found, mitigation would consist of the combination of scraper/intelligent pigging and chemical treatments including corrosion inhibitor, biocide, and oxygen scavenger. In most cases the pipes are not cut open.

Post Assessment — During this, all data gathered and tests performed on the first three phases are analyzed and the effectiveness of the DG-ICDA process is assessed. Reassessment intervals are determined as well.

6.9.9 Stress Corrosion Cracking Direct Assessment (SCCDA)

Pre-Assessment — According to NACE Standard SP0204, the "objective of the pre-assessment step is to collect and analyze historic and current data to prioritize potentially susceptible segments of pipelines and help select specific sites for excavation within those segments." This step includes data collection, prioritization and initial identification of candidate sites for additional indirect surveys and subsequent direct examinations.

Indirect Inspection — During indirect inspection, aboveground and/or other types of measurements are done supplement data from the pre-assessment step. Some of these measurements might include a CIS, coating fault survey, geological surveys, or other data similar to those gathered for ECDA.

Direct Examination — Per the Standard SP0204 (latest version), the pipe is examined at locations chosen after pre-assessment and indirect examination. The process assesses the presence, extent, type, and severity of SCC at the individual dig sites. Data is collected for the development or refinement of a predictive model.

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

Glossary of Terms

Terms	Definition
ALARP	As Low As Reasonably Practicable
P_i	Probability
C_i	Consequence
HSE	Health, Safety And Environment
LNG	Liquefied Natural Gas
CSFM	California State Fire Marshall
F_o	Failure Frequency/Year
ILI	In-Line Inspection
HCA	High Consequence Areas
SME	Subject Matter Expert
LIF	Leak Impact Factor
LV	Quantity Of Liquid Or Vapor
PH	Product Hazard
VCE	Vapor Cloud Explosion
BLEVE	Boiling Liquid Expanding Vapor Explosion
VCE	Vapor Cloud Explosion
UVCE	Unconfined Vapor Cloud Explosion
LFL	Lower Flammability Limit
FMECA	Failure Modes, Effects, And Criticality Analysis
HAZOP	Hazard And Operability
RBI	Risk-Based Inspection
ISO risk line	Line Of Constant Risk

Chapter 7: Integrity Verification/ Assessment

After completing this chapter, students should be:

- Familiar with pipeline integrity verification/assessment.
- Knowledgeable about the In-Line Inspection (ILI) method for integrity assessment.
- Familiar with the hydrostatic testing method for integrity ass-essent.
- Knowledgeable about the three key Direct Assessment (DA) methods for integrity assessment.

7.1 Performing an Overall Assessment on a Pipeline System

To appreciate the significant value of pipeline integrity assessment, it will help to review the key elements of an integrity management program (IMP) as illustrated in Figure 7.1.

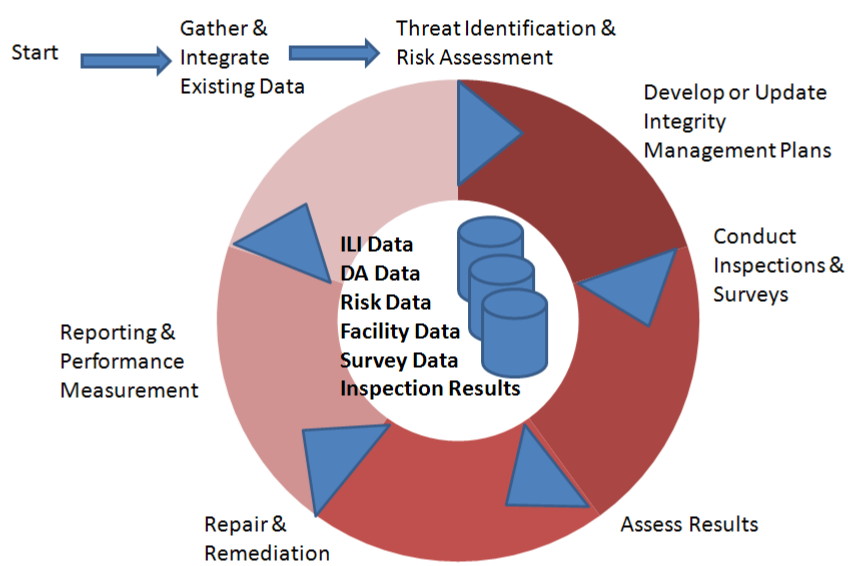


Figure 7.1 Integrity Management Circle

Risk assessment results, the pipeline/segment rankings, or priorities are used to develop and/or update the baseline assessment plan; this includes developing schedules to perform pipeline integrity assessments and selecting appropriate assessment methodologies for each prioritized pipeline segment. These assessments are carried out using three primary assessment methods:

- In-line inspection that entails running "smart pigs" through the pipeline segments to evaluate internal and external corrosion, cracks, and deformations;
- Pressure testing that entails using water or gas to pressurize the pipeline segment and establish a new pipeline's maximum allowable operating pressure (MAOP) or to up-rate the existing pipelines MAOP; and
- Direct assessment, which is a structured, multi-step evaluation process, including excavation to examine and identify potential problem areas relating to internal corrosion (ICDA), external corrosion (ECDA), and stress corrosion cracking (SCCDA). It is an a method to assess covered pipeline segment integrity.

Integrity assessment primarily identifies, monitors, and measures the deterioration mechanisms and rates of deterioration of specific threats. It helps determine how critical the indications are, when the deterioration will reach a critical stage, or when failure might occur. Based on these findings, defects are classified into three categories: (a) **immediate**, defects that are at failure points; (b) **scheduled**, defects that are significant but not at failure points; and (c) **monitored**, defects that will not fail before the next inspection.

7.2 Integrity Assessment Methods

7.2.1 In-Line Inspection (ILI)

7.2.1.1 Overview

In-Line Inspection (ILI) is a versatile integrity assessment method. The inspection could be carried out with various types of ILI tools like corrosion detection tools, crack detection tools, deformation detection tools, self-propelled, fluid-propelled, cable-pulled and crawler tools. All these tools are cylinder-shaped devices generally called "smart" or "intelligent" pigs. Aside from corrosion, other defects and features detected by ILI smart pigs include pipe seam defects, dents, gouges, mid-wall defects, bends, and valves. Generally they are used to perform the following pipeline integrity services:

- diameter/geometry measurements
- curvature monitoring
- pipeline profile
- temperature/pressure recording
- bend measurement
- metal-loss/corrosion detection
- photographic inspection
- crack detection
- wax deposition measurements
- leak detection
- product sampling
- mapping

Smart pigs record data about a pipeline's integrity; the data is downloaded, analyzed, and used by ILI professionals, engineers, and project managers to determine what measures should be taken to ensure future pipeline integrity. There are several types of smart pigs used in the pipeline industry. The different types of pigs are discussed in the following sections.

7.2.1.2 Tools

Utility Pigs

Utility pigging is an effective method to remove accumulated liquids and solids in a pipeline. While the pipeline is in service, operators will often pig the line to maintain line efficiency and help control corrosion by removing liquids/solids that may have accumulated in the low spots of the pipeline. Periodic removal of accumulated biofilms, deposits, and liquids from pipelines reduce the probability of MIC or under-deposit corrosion. When a line is pigged, samples should be collected and tested to gather data about the corrosivity of the internal pipeline environment.

Through the different stages in the life of a pipeline, the type and frequency of pigging varies – as does the type of pigs. Pigs generally used to assist in the environmental control of internal corrosion are the conventional pigs commonly described as cleaning pigs for "on-stream" pigging. Utility pigs are designed to remove solids or accumulated liquids and debris in the pipeline, to increase efficiency and lower pipeline operating costs. Examples of utility pigs follow.

Figure 7.2 depicts typical utility pigs. It shows an operational (cleaning) pig, used to clean the inside of the pipe, and a sealing pig, used to provide a tight seal to either sweep liquids from the line or to separate two dissimilar liquids in the pipeline. Other types of utility pigs include spherical pigs (Figure 7.3), polyurethane cast pigs (Figure 7.4) and urethane foam pigs (Figure 7.5). Figure 7.6 shows mandrel pigs with various components that can be assembled onto a mandrel to configure it for specific duty.

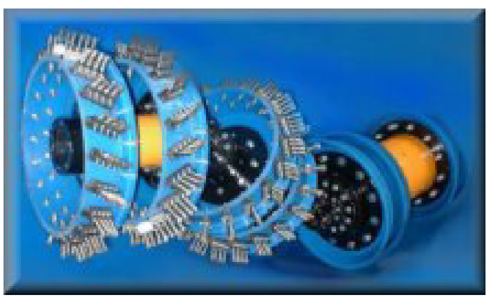


Figure 7.2 Utility Pigs: Cleaning and Sealing Pig

Figure 7.3 Spherical Pig

Figure 7.4 Polyurethane Cast Pigs

Figure 7.5 Urethane Foam Pigs

Figure 7.6 Mandrel Pig

Geometry Pigs

Geometry or caliper pigs (Figure 7.7) are equipped with electro-mechanical arms to measure the bore of a pipeline. These pigs can identify dents, wrinkles, deformations, ovality changes, and other changes caused by significant internal corrosion. Geometry tools can also sense changes in girth welds and wall thickness. In some cases, these tools can detect bends in pipelines. The geometry tools used to detect deformation anomalies also provide the orientation, location and depth measurement of each dent. Geometry tools can be used in both hazardous liquid and natural gas pipelines.

Figure 7.7 Geometry Pigs

Magnetic-Flux Leakage (MFL) Tool

Figure 7.8 depicts a MFL tool (probably the most commonly used ILI tool) which provides information about the characteristics inside the pipeline. It uses a circumferential array of detectors, consisting of strong permanent magnets, to magnetize the pipe wall to near saturation flux density.

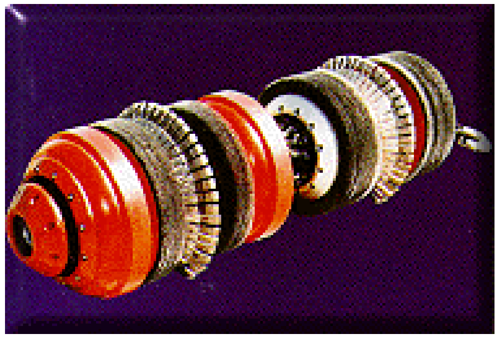
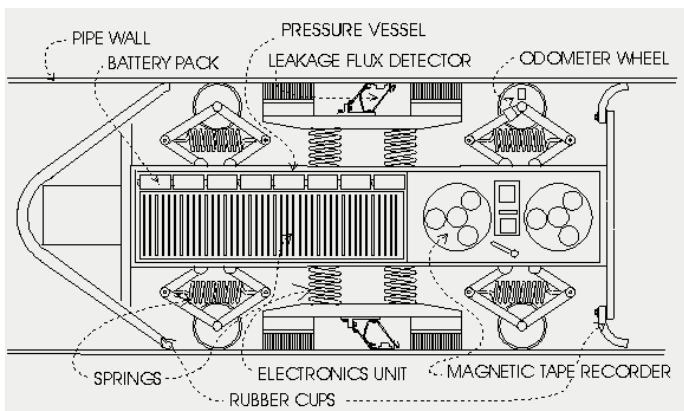


Figure 7.8 MFL In-line Inspection Tool

Any abnormality in a pipe wall, such as a corrosion pit, causes magnetic flux leakage near the pipe's surface. Probes or induction coils within the MFL tool detect the flux leakage. The data is downloaded, analyzed, and used to determine what measures should be taken to ensure pipeline integrity.

Figure 7.9 depicts the dynamics and schematic of a MFL Tool.



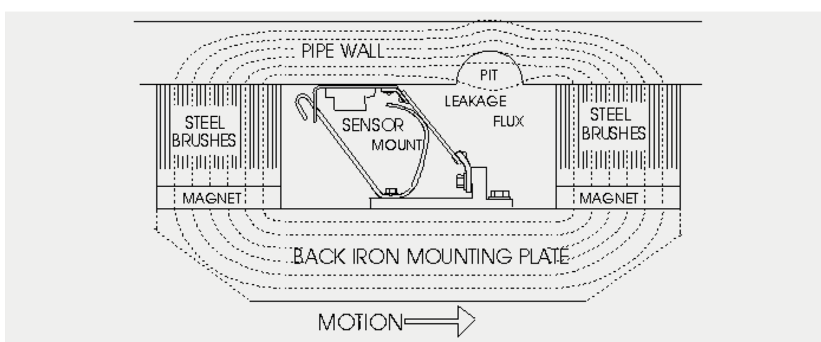


Figure 7.9 MFL Schematic Diagrams

Ultra-Sonic Testing (UT) Tool

Ultra-sonic tools measure pipe wall thickness and metal loss. Successful deployment of a UT tool requires pipe cleanliness, specifically removal of any paraffin build-up within the pipe. This is especially important in crude oil lines. Using a cleaning pig prior to using UT tools is recommended.

There are two types of UT tools commonly used (Figure 7.10) for hazardous liquid pipeline inspections: compression and shear wave tools. Compression wave UT tools are equipped with transducers that emit ultrasonic signals perpendicular to the surface of the pipe. An echo is received from both the internal and external surfaces of the pipe and the wall thickness is determined by timing these return signals and comparing them to the speed of ultrasound in pipe steel.

Shear wave UT tools (also known as circumferential UT tools or C-UT). This technique detects longitudinal cracks, longitudinal weld defects, and crack-like defects (as observed in SCC). Shear wave UT tools are categorized as liquid coupled tools. They hear waves generated in the pipe wall by the angular transmission of UT pulses through a liquid coupling medium such as oil or water. The angle of incidence is adjusted so that a propagation angle of 45 degrees is obtained. This technique is appropriate for longitudinal crack inspection.

Figure 7.10 Ultrasonic Inspection Tool

"Pig Trap" or Pig Launcher and Receiver

Pig traps are used to insert pigs into a pipeline then launch, receive, and finally remove them without flow interruption. Pig traps are not generally proprietary products and are usually fabricated to specifications drawn up by the user. However, pig trap closures are proprietary products and form a critically important part of a pigging system. Safety is a major consideration in the selection of a closure. All closures must have a built-in safety lock to prevent them from being opened while the trap is pressurized. Figure 7.11 illustrates a typical pig trap.

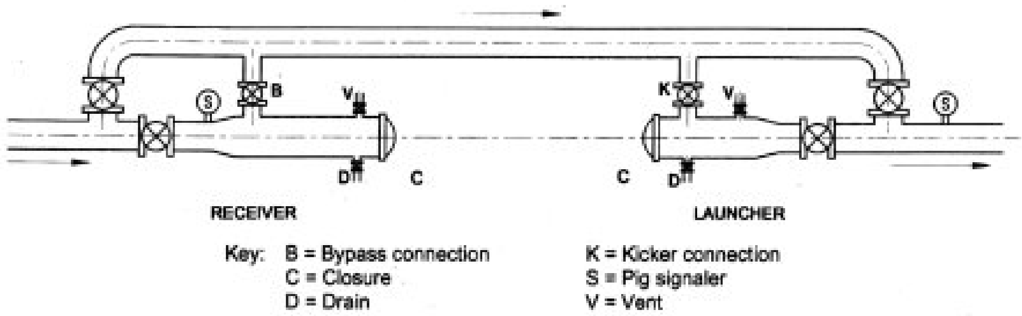


Figure 7.11 Pig Launcher and Receiver

7.2.1.3 ILI in Liquid and Gas Pipelines

Smart pigs are generally effective in identifying the current static state of corrosion in pipelines. Multiple pigs that run during a specified time provide ample data to analyze corrosion growth and to differentiate between areas of new growth and areas of continued growth. The type of fluid running in a pipeline affects the effectiveness of smart pigs. ILI application methods in gas and liquid pipelines differ fundamentally. Liquid lines typically operate at low enough speeds that ILI operation does not restrict throughput. In fact, normal liquid flow is supplemented sometimes with additional product to reach the minimum required inspection velocity. However, a liquid products pipeline operator may not be willing to risk product contamination by running an ILI tool in critical batches such as aviation fuel.

Liquid lines are ideal for ultrasonic tools because the liquid medium provides an effective coupling between the tool sensors and the pipe wall. On the other hand, gas acts as a barrier to ultrasonic signals that are ineffective in gas pipelines. To resolve this, gas line ultrasonic tools are run in a liquid slug. Aside from complicating the inspection, the presence of potentially corrosive liquid in an otherwise dry gas pipeline can be very counter productive.

An additional problem of ILI use in gas pipelines is linear velocity, particularly for magnetic flux tools that are 24 inched (61 cm) in diameter. Gas pipelines operate at speeds that are well in excess of the maximum allowable ILI speeds. Because of this, some tools are equipped with a speed control bypass mechanism. The ILI tool is controlled, in part, by the amount of bypass flow across its body. In fact, the dynamic behavior of ILI tools depends on differing pressures across its body and the variable bypass flow. The system dynamics include driving gas flow behind the tool, expelled gas in front of the tool, bypass flow, and the dynamics of the tool itself. Its function is complex and, in the end, the procedure restricts the capacity of gas pipelines.

Whether in gas or liquid form, sour service is harmful to most ILI tools. Avoid costly repairs by selecting tools that are fit for the specific service. Any chemical other than oil or gas that is expected to be present should be reported to the vendor ahead of time to verify the tools suitability for use. When there is uncertainty about the conditions within a pipeline, the “progressive” pigging strategy should be put in place to reduce the risk of a stuck pig. This strategy begins with a versatile pig that is capable of moving through the pipeline without getting stuck, and gradually progresses to running smart pigs that are more robust. Developing an effective smart pigging program requires a number of essential components. In addition to sufficient training for personnel, high standards and specific procedures must be established. Excellent documentation must be created and made available on pigging topics including:

- Pigging
- Pig trap operation
- Requirements and purpose of pigging
- Types of pigs, including relative performance
- Pig selection
- Pigging program strategy
- Pigging schedules and a “master” schedule
- Pig launching procedures
- Pig receiving procedures

- Safety and contingency plans

Please note that extreme caution must be used during all pig launching and receiving procedures. Ensure that all personnel who are not directly involved with the procedures are clear of the area. Eliminate all sources of ignition. Keep fire extinguishers readily available on site. Do not open the closure until the trap has been depressurized. Do not allow personnel to stand in the projected path of the end closure while opening. Have all personnel wear protective clothing and equipment when loading or removing a pig from a trap.

Pig Tracking

The pig running in the pipeline should be tracked continuously. Tracking locations are usually located downstream from pipeline appurtenances or intermediate booster stations to ensure that the pig negotiates and clears all in-line facilities. Pig tracking crews typically consist of:

- An adequate number of individuals trained to use of pig tracking equipment, tracking calculations, line finding equipment, etc.
- An adequate number of vehicles suitable for the right-of-way being traveled
- Equipment capable of real-time communications at any time during the tracking activities
- An adequate number of sets of functioning acoustic pig tracking equipment

When an electronic transmitter is used to track, make sure it is mounted properly and that the device is operational before you launch the pig. It is mandatory that the pipeline operations control center should know of all tool run activities, including, but not limited to the following:

- When the tool is ready for launch
- When the tool has been launched and tracking is underway
- Any time irregularities are noted in the flow or pig travel
- Know in advance any scheduled changes in pipeline flow conditions (as identified in the inspection procedure)

- Confirm the pig position every three hours and check that tracking personnel are not incapacitated
- Confirm the pig position several times before it arrives at any intermediate booster station, pig signal, or receiving location
- When the pig has been received the pipeline can return to normal operation

Benchmarks and Aboveground Markers (AGMs)

Benchmarks are discrete survey points along the pipeline route that are location reference points. Readily identifiable permanent pipeline features, such as valves, cased crossings, tie–ins, or other system adjuncts, can be used as benchmarks. These system adjuncts, detectable by the inspection tools, can be used as known features when referencing the locations of metal loss anomalies. Benchmarking corrects for ILI measured distance inaccuracies and minimizes in-the-field measurements to locate defects or features. Benchmarking also provides reference points to track the ILI tool as it progresses through the pipeline.

AGMs on the other hand, are either permanently attached to the pipeline (by magnets, for example) or are portable. AGMs should not be placed next to or near benchmarks; they should be placed in easily accessible locations on the pipeline route. They are usually spaced at specific minimum intervals; closer spacing produces a more accurate location.

AGMs are deployed by operating personnel prior to and during a pig run. The number of AGMs depends on inspection length, the number of pigs, and the intervals between markers. The recommended spacing between markers is one mile, if practical. All marking equipment and instructions for use generally are provided by the inspection service provider.

AGM documentation should include the following:

- Vehicle accessibility (map or sketch of how to get to the location)
- Drive time (in minutes) between AGM locations
- Parties to be contacted (landowners, agencies, etc.) prior to going to the AGM point

- Distance and method used to find and set the AGM point
- Notes showing establishment of the AGM location
- Pipeline station number of the AGM point
- Identification number of the AGM point
- Name of the AGM point
- Milepost of the AGM point
- Global positioning system (GPS) latitude, longitude, and elevation of the AGM point

All AGM locations must be recorded with reference to permanent repeatable grade level reference points and should be accurately documented so the position can be re-established in the future.

7.2.1.4 ILI Standards

The three major standards that address the requirements and processes for qualification of ILI systems, including the ILI tools, software, and personnel requirements to operate and analyze the results are:

- API 1163, "In-line Inspection Systems Qualification Standard," 2005.
- ASNI/ASNT ILI-PQ-2005, "In-line Inspection Personnel Qualification and Certification," 2005.
- NACE Standard SP0102, Item No. 2109, "Recommended Practice: In-Line Inspection of Pipelines" (Houston, TX: NACE, 2002.)

An essential key companion guide to NACE Standard SP0102 is:

- NACE Publication 35100, Item No. 24211, "In-Line Nondestructive Inspection of Pipelines," (Houston, TX: NACE, 2000.)

Another relevant industry standard is from the European Pipeline Operator Forum:

- "Specification and Requirements for Intelligent Pig Inspection of Pipelines," version 3.2, January, 2005.

Non-standard, relevant publications pertaining to in-line inspection include:

- In Line Inspection: Session 8 of the Web Conference Series, "Safely Managing the Life Cycle of Pipelines."
- The Pigging Products and Services Association, "An Introduction to Pipeline Pigging," 5th ed. ISBN 0-901360-33-3.
- Cordell, Jim, and Vanzant, Hershel. The Pipeline Pigging Handbook, 3rd ed. ISBN 0-9526448-1-9.
- Tiratsoo, John, ed. Pipeline Pigging and Integrity Technology, 3rd ed. ISBN 0-9717945-2-9.

7.2.2 Hydrostatic Testing

The use of pressure testing (or "hydrotesting") to inspect pipelines is based on the supposition that, after defects are removed that failed above the maximum operating pressure (MOP), the line is then safe to operate at the MOP and below. Hydrotesting is both a strength test and a leak test (depending on the threats being assessed). It is utilized for post-construction testing prior to startup, and after the pipeline has been in service for a while.

The pipeline is filled with water; the pressure raised to a specified level for a pre-determined length of time using design and service pressure criteria. It is a low-technology technique whose integrity conclusions are relevant only at the time of the test.

7.2.2.1 Overview

Basic considerations in hydrostatic testing are:

- The pipeline must be taken out of service
- Only the critical flaws leading to failure at the time of testing are identified; sub-critical flaws are not identified
- A large volume of water must be used and then disposed of in accordance with environmental regulations
- Introduction of water into the pipeline creates a corrosion risk; the pipeline must be dried before it can be returned to service

- Hydrotesting is destructive; this method should not be used in highly populated areas

Water is the medium for hydrotesting, however, liquid petroleum (with a Reid vapor pressure of 7 psia) may be used, subject to conditions detailed in API RP 1110. Some pipeline operators mix a percentage of methanol with the water to minimize exposure of the interior wall to the electrolyte. While these measures may partially solve a problem, they introduce other issues that must be included in overall pipeline integrity considerations.

7.2.2.2 Tools

The following tools are used for hydrotesting:

- A high-volume pump
- A clean filtered test medium, usually water
- A chemical injection pump to introduce treatment chemicals, leak detection dyes, or gases
- A flow meter to measure the pipeline fill
- A high-pressure, variable speed, positive displacement pump, equipped with a stroke counter that is capable of pressurizing the pipeline to a level that exceeds the specified test pressure. The volume per stroke of the pump should be known unless the test medium is otherwise measured during filling and pressurization.
- A relief valve
- A portable tank for excess test medium, or to retain makeup fluid
- An appropriate pressure gauge capable of sensing and displaying incremental pressure increase or decrease
- A deadweight tester in increments of 1 psi (6.7 kilopascals), whose certificate of calibration is less than one year old; an equivalent pressure-sensing device may be acceptable
- A continuous-recording pressure-measuring device that creates a permanent record of pressure versus time; before use, it should be calibrated using the deadweight tester

- An appropriate temperature gauge capable of sensing and displaying incremental temperature increases or decreases of no less than 0.1° F (0.05° C)
- A continuous-recording temperature-measuring device that creates a permanent record of temperature versus time
- A thermometer solely dedicated to provide the ambient temperature
- All temperature measuring and recording devices should be checked for accuracy before use; accuracy verification should be documented
- Protective storage for all the tools and instruments
- Operational (cleaning) double-sealing pigs, scrapers, and spheres to clean and remove debris, water, and air from the pipeline; the pigs can be used to introduce or remove test medium from the test segment
- Temporary manifolds, pig launchers, pig receivers, and other connections as needed
- Electronic communication equipment to coordinate test activities
- Tools to isolate the pipeline segments for leak test or for repair
- Replacement pipes, valves, gaskets, and other pipeline attachments that might fail during pressure test

7.2.2.3 Methods

Please note: safety is paramount; observe all safety precautions.

Before filling the pipeline segment with test fluid, a sizing, caliper, or deformation (geometry) pig should be run through the segment to identify geometric abnormalities. Then run a train of cleaning pigs to remove debris, sediments, parafins, etc. A high volume pump should then pump the pressure medium into the segment at about 2-3 mph. At this rate the pig will move at the right speed to maintain a tight fit; continue pumping until the segment is filled. The pig will be separating the test medium from the pipeline content (it should be fitted with locators for tracking).

The pipeline segment should be pressurized only after air and/or gas have been bled out and the section packed.

The segment's pressure should be increased (without surge) to the correct point; during this process the flow rate should be monitored and logged so that the pressure-volume can be charted. At 80% to 90% of the desired test pressure, the pressurization rate should be reduced systematically until it is 100% of the specified minimum yield strength (SMYS). A deadweight tester or electronic pressure-sensing device should be used to measure the actual pressure.

When the test pressure is reached and pressurization halted, all pipeline connections should be checked for possible leakage. If there is no leakage, when the temperature and pressure of the system have stabilized, the pressurization system should be completely isolated from the pipe. The pipe should be observed for the length of time detailed in ASME 31.8, which specifies the test pressure, test duration, test medium, and test conditions according to the threats being addressed.

Monitor and log the temperature and pressure of the pipeline until the pressure test is completed. Record deadweight tester pressures checks at 30-minute intervals from the beginning to the end of the test. Log weather changes that affect the temperature and pressure recordings as well as the medium volume added or subtracted during the testing. Test failures, bleed-offs, and re-pressurizations should be logged and described in detail. Replace any valve, fittings, or pipe sections that fail, and then submit them for failure analysis. The minimum required set of test records follow:

- Test plan
- Deadweight calibration certificate
- Pressure-time recordings with related information
- Temperature-time recordings with related information
- Pressure test record and certification including:
    - a) qualification calculations
    - b) pressure and temperature log
    - c) record of failures and possible explanations
    - d) profile of pipeline showing the elevation if elevation

differences exceed 100 ft. (30 meters)

Once the pressure testing is complete, displace and dispose of the test medium according to the prevailing regulations; dry the pipeline; use spheres, squeegees, or other pigging devices to displace the test medium. If water is the test medium, a biocide treatment may be required following the completion of the test.

7.2.2.4 Standards

API RP 1110 "Pressure Testing of Liquid Petroleum Pipelines" is a key reference for hydrotesting new and existing liquid petroleum pipelines. It provides the fundamental recommendations for minimum procedures, tools, and other factors.

Pipeline integrity assessment code requirements are in ASME 31.8, which specifies the test pressure, duration, medium, and conditions for the threats being assessed. It also addresses the use of hydrotesting for re-qualification of a pipeline for liquid service.

Otherwise, the general code requirements for pressure testing are in ASME B31.4 "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols" which delineates the use of hydrotesting for:

- newly constructed pipelines and replaced segments of existing pipelines,
- qualification of existing pipelines for an operating pressure higher than the previously established operating pressure, and
- re-qualification of existing pipelines for continued operation at the previously established operating pressure.

7.2.3 Direct Assessment (DA)

When the pipeline and/or flowline segments cannot be pigged or subjected to hydrotesting, to find time-dependent defect types three inspection methods can be used: internal corrosion direct assessment (ICDA), external corrosion direct assessment (ECDA), and stress corrosion cracking direct assessment (SCCDA). Each is a non-destructive inspection method not limited to unpigable pipelines. However, operator familiarity and diligence is required accomplish the assessment successfully. Confirmatory direct assessment is part of each of the three DA methods.

Direct assessment is a structured process that uses data and information from indirect pipeline surveys, direct examination, along with all other relevant information (e.g., design, construction and operating data) to assess the integrity of buried pipelines. It is a four-step process consisting of (1) pre-assessment, (2) indirect inspection, (3) direct examination, and (4) post assessment. The approach is straightforward and it uses mature technology that can be run by in-house engineering personnel.

7.2.4 Internal Corrosion Direct Assessment (ICDA)

ICDA assesses the likelihood of internal corrosion in a given length of pipe within a transmission pipeline. Although the basic concepts of ICDA are applicable to liquid lines, NACE SP0206 is specifically targeted to dry natural gas (DG) transmission lines that might experience episodic upsets (e.g., water in the system making it impossible for the product to meet specifications. Dry gas contains a nominal amount of water, less than 7 pounds per million standard cubic feet of gas (112g/m^3). The DG-ICDA process requires specific tools for pipelines with extensive corrosion damage and addresses the following issues:

- **Integrity assessment** answers the question “Is there a risk of internal corrosion in this facility?”
- **Corrosion investigation** determines if any actions are required to control internal corrosion in the facility.
- **Mitigation and monitoring** answers the question “What must be done to mitigate internal corrosion in this facility?”
- **Assessment frequency** answers the question “How is integrity managed long-term?”

The specific concern of DG-ICDA is the accumulation of water in the pipeline. Simply stated, if corrosion occurs, it will happen at locations where water accumulates first. Therefore, the basic assumption is that examining the pipeline for corrosion where water would first accumulate will provide the data that can describe the condition of the pipe downstream. Conversely, if the locations that are most likely to accumulate water have not corroded, other downstream locations are less likely to accumulate water and are most likely free of corrosion. This implies that inspection and other ICDA examinations of pipeline segments outside of a high consequence area are sufficient to satisfy the integrity requirements inside the same area.

The indirect inspection aspect of DG-ICDA (Figure 7.12) uses multiphase flow modeling to predict the critical angle of inclination that would hold the first accumulation of water. Typical parameters for flow modeling include the following:

- Maximum superficial velocity of 25 ft/sec (7.6 m/sec)
- Pipe diameter from 4 to 48 inches (0.1 to 1.2 m)
- Pressure from 500 to 1100 psi (3.4 to 7.6 MPa)
- Temperature from 60^{o}F (16^{o}C) to 130^{o}F (54^{o}C) downstream of compressor station discharge

In effect, DG-ICDA assesses the impact of short-term upsets on pipeline integrity. Under normal operating conditions, gas transmission lines would not internally corrode because an upstream gas-dehydration treatment facility removes the water that causes corrosion. If the upstream gas processing facility malfunctions allowing liquid water (and/or other possibly corrosive liquids) to enter the downstream pipeline, internal corrosion will occur. Other corrosive liquids emanating from a processing facility malfunction could include glycol and wet gas, but are not a primary concern. Leftover hydrotest water and produced water would also be corrosive, but are outside the scope of DG-ICDA.

NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)" describes the four-step process characteristic of DA. The approach was designed assess internal corrosion in gas transmission pipelines and ensure pipeline integrity, reliability, and public safety. The methodology includes these steps:

5. **Pre-Assessment:** essential current and historic operating data are collected; feasibility of DG-ICDA is discussed; DG-ICDA regions are defined;
6. **Indirect Inspection:** multiphase flow predictions made; a pipeline elevation profile developed, and sites identified where internal corrosion may be present; modeling to predict corrosion

susceptibility factors in gas composition, water chemistry, bacteria, and fluid dynamics; these corrosion rate features act independently;

7. **Detailed Examination:** predicted susceptible locations are excavated and examined in detail using ultrasonic and radiographic technologies to determine whether internal corrosion metal loss has occurred; one or two locations are normally excavated; and
8. **Post Assessment:** data collected from the first three steps is analyzed to assess the effectiveness of the DG-ICDA process and determine reassessment intervals.

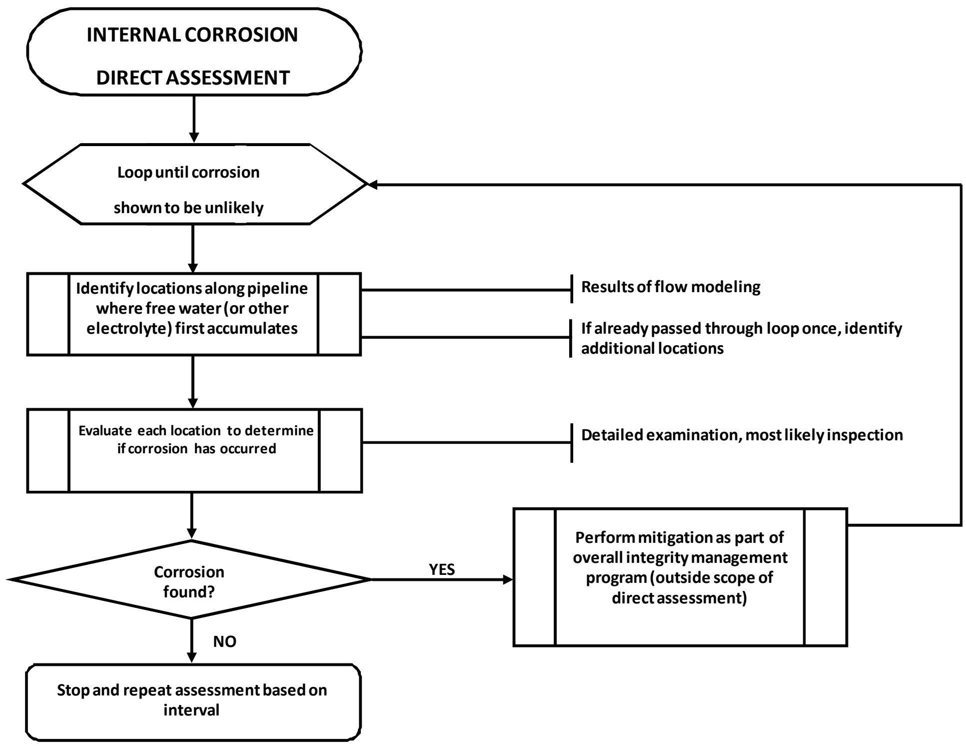


Figure 7.12 Internal Corrosion Direct Assessment

Extensive corrosion at many locations suggests that the transported gas was not normally dry, and this recommended practice is not applicable. Details of the DG-ICDA four steps follow:

7.2.4.1 Pre-Assessment

Pre-assessment includes data collection, assessment of DG-ICDA feasibility, and identification of DG-ICDA regions. The minimum data set required includes:

- Operating history
- Defined pipeline segment length
- Elevation profile
- Features with inclination
- Diameter and wall thickness of pipeline segment
- Typical operating and maximum pressure range
- Maximum and minimum flow rates over the range of operating pressures
- Typical operating and maximum temperature range
- Water vapor content
- Types and locations of inputs/outputs
- Corrosion inhibitors
- Upsets
- Type of dehydration
- Hydrostatic test information
- History of repair/maintenance data
- History and location of leaks/failures
- Gas quality
- Corrosion monitoring
- Existence and location(s) of any coatings defects
- Other internal corrosion data

Note: *Additional data can be included. The data collected at this time often include data typically considered in an overall pipeline risk (threat) assessment. Depending on the pipeline operator's integrity management plan and its implementation, the operator* *may conduct the pre-assessment step in conjunction with an External Corrosion Direct Assessment (ECDA) and/or other risk assessment effort.*

DG-ICDA regions are chosen based on the data collected. A region is a portion of pipeline of a defined length that does not include the possible presence of water. In defining DG-ICDA regions, the operator must include regular process changes (e.g., temperature and pressure). If such changes take place routinely, the segment length should be designated a separate DG-ICDA region, or the critical inclination angle at any point within such a region must be based on the local pressure and temperature *at that point*.

To decide if ICDA is feasible, the operator should examine the data to determine whether conditions exist that would preclude DG-ICDA application or indirect inspection tools. Generally, the following conditions are required in order to apply NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA):"

- The pipeline should not normally contain any liquids, including glycols.
- The pipeline should not have previously been in service for which DG-ICDA was not applicable, *unless* it can be shown that either internal corrosion did not occur in the previous service or that previous damage has been separately assessed.
- The pipeline must not have an internal coating that provides corrosion protection. For pipelines with discontinuous protective coating, indirect examinations can be performed only at locations that are not internally coated.
- If history indicates internal corrosion at the top of the pipeline from wet gas (i.e., from condensing water), NACE SP0206 is not applicable.
- Pigging affects areas where liquids could collect, which directly affects the distribution of internal corrosion in a way that DG-ICDA cannot predict. The DG-ICDA may not be appropriate for pipelines that have been routinely pigged. The operator must provide technical justification before DG-ICDA is conducted on a pipeline that has any history of cleaning pigs.

- Use of corrosion inhibitors may preclude application of DG-ICDA because the effectiveness of the inhibitor might not have been uniform along the pipeline length.
- Pipelines that contain accumulations of solids, sludge, biofilm/biomass, or scale should not be assessed using DG-ICDA standards unless the influence of those materials is evaluated carefully. Operators must determine whether accumulations of solids are significant enough to influence the validity of the DG-ICDA results through any of the mechanisms described in NACE SP0206.

7.2.4.2 Indirect Inspection

The objective of indirect inspection for DG-ICDA is to perform multi-phase flow calculations using the collected data to determine critical inclination angles of liquid holdup. This is to predict the locations most likely to have internal corrosion in each DG-ICDA region. For each DG-ICDA region, this process includes each of the following activities:

- Calculate the complete flow dynamics within the pipeline; model the flow and accumulation of water for each potential DG-ICDA region.
- Determine the complete inclination profile of the pipeline.
- Integrate the flow calculation results with the pipeline inclination profile to determine sites where internal corrosion may be present; DG-ICDA region selection should consider inclination angles at road crossings, rivers, drainage ditches, and other locations.

7.2.4.3 Detailed Examinations

According to NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)," the objectives of the DG-ICDA examination are to: (1) excavate and inspect pipelines to identify and characterize internal corrosion features, (2) determine internal corrosion at selected locations, and (3) use the findings to assess overall condition of the region.

In a detailed examination, downstream locations with an inclination greater than the specified critical angle are inspected. If no angles greater than the critical angle are found, the location with the highest inclination should be examined. If corrosion is discovered one additional location should be selected for validation purposes.

To be doubly sure that the locations most likely to have internal corrosion are actually being examined, at least two inspections must be performed in the sub-region between the beginning of the DG-ICDA region and the first site examined. If there is only one inclination upstream of the first site inspected, only one site must be inspected in the sub-region. If there are no inclinations in the sub-region upstream of the first site inspected, no sites need to be inspected in that sub-region.

If the detailed examination process identifies extensive and severe internal corrosion, the operator should return to pre-assessment because the appropriateness of DG-ICDA is then in question. The ICDA process optimizes the *search* for corrosion-susceptible sites and *targets* locations of likely corrosion accurately.

When corrosion is detected, nondestructive tests are then used to determine the remaining wall thickness of the pipe (in accordance with established procedures and applicable NACE standards by trained and experienced personnel). The operator should also calculate the remaining strength of the pipe at locations where there is corrosion according to RSTRENG, ASME B31G, Modified ASME B31G, or DNV Standard RP-F101.

If corrosion is found, a combination of scraper/intelligent pigging and chemical treatments can be used. In most cases, the pipes should remain uncut if possible. During excavation, the operator may install corrosion coupons, electronic probes, UT sensors, or other corrosion monitoring devices to allow the operator to determine inspection intervals and monitor places susceptible to corrosion. ICDA can optimize selection of appropriate locations for placing corrosion monitoring tools. The two inspection techniques generally used during pipeline excavation in ICDA are ultrasonic and radiography testing, discussed below.

Ultrasonic (UT) Technique

Ultrasonic testing is used to measure thickness losses due to internal corrosion; these measurements are used to calculate structural integrity pressure. For this purpose, 2 x 10 ultrasonic transducer grid arrays are attached horizontally to the outside of the pipeline at the 6 o'clock position. The data from each transducer is analyzed to calculate both the average general corrosion rate and increases in corrosion area. The transducers would need a broader beam to inspect a wider area, but each transducer's resolution should be high (about +/-2 mils). On the other hand, single high-resolution UT transducers do have resolutions as low as 0.1 mil, which is comparable with probe monitoring. If significant corrosion is found, pipe repair or replacement may be required.

Radiography Technique

Radiography testing measures thickness at specific intervals. The X-ray source is located at the 12 o'clock position and the film at the 6 o'clock position on the exterior surfaces of the excavated pipe segment. Like in the ultrasonic measurements, if significant corrosion is found, pipe repair or replacement may be necessary.

7.2.4.4 Post Assessment

The objectives of the Post Assessment phase in DG-ICDA are (1) to assess the effectiveness of DG-ICDA, and (2) to determine the reassessment intervals. The effectiveness of the DG-ICDA process is determined by comparing the actual corrosion with the DG-ICDA predicted locations. It is the operator's responsibility to determine reassessment intervals. Determining reassessment intervals should take several factors into consideration:

- Periodic re-examination of sites that have suffered internal corrosion at a prescribed frequency to calculate the growth rate trend;
- Installing one or more corrosion monitoring devices at (1) sites where flow-modeling predicts liquid accumulation, (2) sites that show internal corrosion, and (3) at other representative locations;
- Results of a corrosion-rate model based on operating conditions, gas quality, liquid composition, and other key factors; and
- Laboratory investigation of corrosion trends in the operating system, based on analysis of operating conditions, pipeline fluids, gas quality, liquid composition, and other key factors.

Whichever method is used to determine the reassessment intervals it should be technically justified and validated by the operator.

7.2.5 External Corrosion Direct Assessment (ECDA)

ECDA is a proactive structured process to improve pipeline safety by assessing and controlling the impact of external corrosion. It is a cost-effective integrity management complement, and sometimes an alternative to ILI and hydrotesting. This is because many transmission pipelines are not "piggable," and many practical factors impede the use of hydrotesting. ECDA has a longer history of use than ICDA and SCCDA; but its scope is limited compared to ILI and hydrotesting. NACE SP0502, "Pipeline External Corrosion Direct Assessment Methodology," addresses the ECDA process.

An important concern of ECDA is the presence of holidays and other anomalies in the external pipeline coating. The basis of the process is that examining the pipeline at these points indicates where external corrosion may have occurred, is occurring, or will occur. ECDA determines CP effectiveness and compliance, AC/DC interference, electrical/geologic current shielding, current attenuation, foreign contacts, and extent of mitigation needs.

External Corrosion Direct Assessment (ECDA) consists of four distinct processes:

- Pre-Assessment
- Indirect Inspection
- Direct Examination
- Post Assessment

7.2.5.1 Pre-Assessment

In this phase, ECDA regions are defined, historical/current pipeline data gathered, feasibility analyzed, and appropriate indirect inspection tools selected.

7.2.5.2 Indirect Inspection

According to NACE SP0502, the objective of indirect inspection is to identify and define the severity of the coating faults, other anomalies, and areas where corrosion has already occurred or may be occurring. A minimum of two indirect inspection techniques are required to be used at or above grade for each ECDA region but the choice of the specific tool depends on it's applicability to the specific pipeline segment. Tool selection should be based on their ability to reliably detect corrosion and/or coating anomalies under the specific pipeline conditions expected.

Of all the indirect inspection techniques available, the Close Interval Potential Surveys (CIPS, or CIS) are perhaps the most commonly used in the pipeline industry. CIS is used to determine the effectiveness of cathodic protection, assess compliance with cathodic protection criteria, locate coating defects and/or areas of coating deterioration, detect AC and/or DC interference, evaluate current attenuation, identify foreign contacts, and detect areas of possible localized corrosion. The list of the primary indirect inspection tools include, but are not limited to the following:

- **Close Interval Potential Surveys (CIPS)**: used at grade level to measure the potential between the pipe and earth at regular intervals along the pipeline
- **AC Current Attenuation Surveys (ACCA)**: used at grade level to measure the overall condition of the coating on a pipeline based on application of electromagnetic field propagation theory; results yielded by ACCA include depth, coating resistance and conductance, anomaly location, and anomaly type
- **Alternating Current Voltage Gradient Surveys (ACVG)**: used at grade level to measure the change in leakage current in the soil along and around pipelines to locate coating anomalies and characterize corrosion activities
- **Direct Current Voltage Gradient Surveys (DCVG)**: used at grade level to measure the change in electrical voltage gradient in the soil along and around pipelines to locate coating anomalies and characterize corrosion activities
- **Cell-to-Cell Surveys**: this is a two-reference-electrode surface survey that measures the potential difference between two matched copper-copper sulfate electrodes in contact with the earth; when used directly over the pipeline route, this method is

able to detect the probable current discharge (anodic) areas thereby helping to locate suspected corrosion anomalies

- **Pearson Surveys**: this technique uses an AC signal injected onto buried pipeline and compares the potential gradient along the pipeline between two mobile earth contacts; it locates all coating defects and foreign metallic objects close to the buried pipeline that can cause corrosion anomalies
- **Soil Surveys**: soil resistivity/conductivity measurements typically are taken at specified intervals (e.g., 1,000 ft) and used to determine the corrosiveness of the soil, and therefore, the potential for corrosion to occur on the pipeline; the lower the resistivity, the higher the conductivity and corrosivity of the soil
- **Guided Wave Ultrasonic Testing (GWUT)**: used to inspect piping within casings under electrically (metallically) shorted, electrolytically coupled, and electrically isolated conditions.

7.2.5.3 Direct Examination

The Direct Examination step of ECDA deals with the condition of the pipe and its environment. It determines what actions will be needed if corrosion defects are found, and addresses and identifies root causes. Once the survey results are integrated, the signals should provide sufficient data to select the best locations for calibration digs and bell holes; these digs should then, in turn, allow operators to prioritize the corrosion according to size and/or severity.

Initially at least two locations are excavated to directly examine defects, coatings adhesion, MIC, and overall soil environment, including electrolyte, pH, resistivity, and potential. This process includes categorizing the indications and conducting root cause analysis. External corrosion is usually caused by either: (1) galvanic cells on the pipeline, or (2) stray current.

Electrolyte sources that provide the essential medium for ionic current (galvanic) corrosion are:

- Differential oxygen concentration at the two surface locations
- Changes in soil type at the two surfaces locations

- Differences in conductivity due to ground water, seawater, salt spray or other weathering conditions
- Metabolic processes of microbes
- Connection to other metals, e.g., well casings to flowlines

Stray current flow between the prevailing environment and the buried pipeline, the second causative factor, can be generated by one or more of the following:

- DC transit systems
- DC mining operations
- Electrical grounding rods
- Grounded cathodic protection system for an adjacent buried pipeline
- DC welding operations
- High voltage DC transmission system
- Geomagnetic (telluric) earth currents
- AC current flow to ground
- Defective electrical isolation joints
- Contact with other metallic structures
- Other direct examination activities to determine the need for repair or corrosion mitigation, in-process evaluation, classification criteria assessment, re-classification and re-prioritization of “immediate,” “scheduled,” and “monitored” indications.

7.2.5.4 Post Assessment

The last step of ECDA, post-assessment, determines the pipeline’s remaining life which becomes the basis to define reassessment intervals, particularly for scheduled indications. This step includes feedback, continuous assessment of ECDA effectiveness, and record keeping.

7.2.6 Stress Corrosion Cracking Direct Assessment (SCCDA)

SCCDA is also a proactive structured process that seeks to improve pipeline safety by assessing and reducing the impact of SCC. Like ICDA and ECDA, it is a cost-effective continuous integrity management complement to in-line inspection and hydrotesting. The process includes visual and physical inspection, electrolyte analysis, metallographic analysis, ultrasonic inspection, and various magnetic particle inspection techniques. ASME B31.8S and NACE Standard SP0204 are fundamental to conducting SCC detection. SCCDA addresses buried onshore production, transmission, and distribution steel pipelines for natural gas, crude oil, and refined products. The comprehensive SCCDA process is illustrated in Chapter 2, Figure 2.24.

The NACE Standard SP0204 standard provides the required guidance to select pipeline segments and dig sites, inspect the pipe, collect and analyze data, establish a mitigation program, define the re-assessment intervals, and evaluate the effectiveness of the SCCDA process. To accomplish these require strict adherence to the four DA processes: (1) Pre-Assessment, (2) Indirect Inspection, (3) Direct Examination, and (4) Post Assessment.

7.2.6.1 Pre-Assessment

This process focuses on collecting and analyzing historical and current data to prioritize which pipeline segments are potentially susceptible to high-pH SCC and near-neutral SCC. The criteria for susceptibility follow:

- Operating stress exceeds 60% of the SMYS
- The operating temperature has historically exceeded 100^{o} F (38^{o} C) *NOTE: this condition is not applicable to near-neutral SCC.*
- The segment is less than or equal to 20 miles (32 km) downstream from a compressor station
- The age of the pipeline is equal to or greater than 10 years
- The coating type is other than fusion-bonded epoxy

The process includes initial identification of candidate sites at which to conduct further indirect surveys and subsequent direct examinations.

7.2.6.2 Indirect Inspections

This is, fundamentally, a continuation of pre-assessment. It focuses on conducting above ground measurements to supplement the data from the pre-assessment process. It makes it easier to more definitively prioritize SCC susceptible segments and select specific sites for direct examination. The above ground measurements might include close interval potential survey (CIPS), direct current voltage gradient (DCVG) survey, alternating current voltage gradient (ACVG) survey, Pearson survey, and AC current attenuation (ACCA) survey (an electromagnetic tool). The goal is to use the measurements to locate coating faults along the pipeline.

7.2.6.3 Direct Examination

This process focuses on examining the pipe at locations chosen after pre-assessment and indirect inspection to assess the presence, extent, type, and severity of SCC. Identifying SCC on a pipeline system normally includes visual and physical inspection, electrolyte analysis, metallographic analysis, ultrasonic inspection, and various magnetic particle inspection techniques. Specifically, the Non Destructive Evaluation (NDE) methods normally used include the following:

- **Visualization by the naked eye**: disbonded coatings are removed and the pipe surface is examined for evidence of cracking
- **Magnetic Particle Inspection**: this aids visualization since SCC colonies are almost never visible to the unaided eye
- **Liquid Dye Penetrant**: enhances visualization of cracks; used on the pipe surface
- **Eddy Current Testing**: this detects cracking directly

If SCC is detected at individual dig sites, direct examination includes the following:

- Verifications of the selected field sites

- Excavation and data collection at the field sites
- Analysis and documentation of SCC type
- Evaluation and documentation of the severity of the SCC

7.2.6.4 Post Assessment

The focus in this part of the process is on determining if SCC mitigation is required; if it is, the type of mitigation to use and its appropriateness, prioritizing mitigation of the defects, determining the re-assessment intervals, and evaluating the effectiveness of the SCCDA approach. The mitigation process chosen could include the following:

- Repair or removal/replacement of the affected pipe length
- Hydrostatic testing
- Performing an engineering critical assessment to evaluate the risk and identify further mitigation methods
- Use of ILI tools to confirm, ascertain, and/or identify the mitigation methods required
- Re-coating

7.2.7 Other Assessment Methods

In-line inspection (ILI) involving the deployment of nondestructive "intelligent" pigs to survey the condition of a pipeline's inside wall, is perhaps the most effective integrity assessment technology. Because of this, regulations are emerging worldwide that require pipeline inspection on a regular basis by ILI technology. There is only one significant problem: of the more than 335,000 miles (540,000 km) of global pipelines, roughly one third are unpigable because of a variety of configuration issues. Pigability involves not only availability of pig launchers and receivers, but also pipeline length, attributes, pressure, flow rate, deformation, cleanliness, etc. Access and valve restrictions, multi-diameter designs, and impassable fittings are generally the most cited pigability problems. For this and other reasons, global research and development efforts are focusing on emerging technologies for pipeline assessment, a few of which are discussed below:

- **SmartScan Tool:** This is an ILI tool launched and retrieved with a new hot-tap system through a hydraulic chute; it includes valve by-pass technology.
- **Airbone LIDAR Pipeline Inspection System (ALPIS):** ALPIS is an airborne remote sensing system that detects natural gas and hazardous liquid pipeline leaks. Data collected with ALPIS incorporates into a geometric information system (GIS) to create mapping databases.
- **Smaller/Simpler MFL Tools:** Development of simplified magnetization tools, consisting of smaller and simpler magnetizers and sensors is ongoing.
- **Continuous Barkhausen Method:** This is a modified MFL ILI tool to inspect mechanical damage, cracks, wrinkles, and corrosion.
- **Long-Range Ultrasonic Method:** This method involves an enhancement of ultrasonic technology to detect degradation in buried, unpiggable pipelines.
- **Assessment Method for Girth Welds and Repair Welds:** This technology involves the development of automated ultrasonic testing for cross-country gas transmission pipelines specifically for girth and repair welds.
- **Guided Wave Inspection of Pipelines:** This process entails developing a high-amplitude guided wave to allow inspection of a significantly longer length of pipeline than is presently done: it uses magneto-strictive sensor (MsS) guided-wave technology.
- **Metal-Loss Detection System for Non-Piggable Pipelines**: This technology uses the skin effect and the difference between magnetic fields at low and high frequency; in operation, low frequency current distributes itself and travels throughout the entire cross-section of the pipe while high frequency current travels along the outer surface of the pipeline (skin effect).
- **Infrasonic Frequency Seismic Sensor System:** Development of an infrasonic gas pipeline evaluation network using low frequency seismic/acoustic (0.1 to 100 Hz) sensors is ongoing; this technology pro-actively detects and warns of unauthorized activity near underground gas pipelines before damage occurs.

- **Intrinsic Distributed Fiber Optic Leak Detection:** This technology uses fiber optic acoustic sensors to detect leaks in pipelines with high precision and low false alarm rates in real time.
- **Piezo Structural Acoustic Pipeline Leak Detection System**: Piezoelectric materials sense leaks, use low-power event recorders to store detected leak data, and an innovative low-power/self-powered acoustic data transmission monitor system to report the leaks and their locations.

7.3 Criteria for Selecting an Integrity Method

The susceptibility of a pipeline segment to corrosion is a major determinant in selecting which integrity assessment method is best. However, you may need more than one assessment tool to address all applicable threats for a segment. A baseline assessment plan should specify the assessment methods best suited to identify anomalies associated with possible threats to the segment.

ASME B31.8S lists 21 threats that could compromise the integrity of a pipeline. These are consolidated into nine categories of failure types, then further consolidated into three time-related defect types:

Time-dependent defect types

1. internal corrosion
2. external corrosion
3. stress corrosion cracking

Stable defect types

4. manufacturing related category
    a. defective pipe seam
    b. defective pipe
5. welding/fabrication related (construction) category
    a. defective pipe girth weld
    b. defective fabrication weld
    c. wrinkle bend or buckle
    d. stripped threads/broken pipe/coupling failure
6. equipment category

a. gasket O-ring failure
b. control/relief equipment malfunction
c. seal/pump packing failure
d. miscellaneous

Time-Independent defect types

7. third-party/mechanical damage category
    a. damage inflicted by first, second, or third parties (instantaneous/immediate failure)
    b. previously damaged pipe (delayed failure mode)
    c. vandalism
8. incorrect operational procedure category
9. weather-related and outside force category
    a. cold weather
    b. lightening
    c. heavy rains or floods
    d. earth movements

In the following section, we will discuss each integrity assessment method in terms of specific pipeline integrity threats.

7.3.1 In-Line Inspection (ILI)

Table 2.8 on page 69 of Chapter 2 shows the inspection purposes, anomaly types, and ILI tools to detect the four categories of failure types. (A thorough discussion of the tools used is located in Chapter 2.)

The ILI method is appropriate for these failure types:

1. internal corrosion
2. external corrosion
3. stress corrosion cracking
4. third-party/mechanical damage

The primary advantages of the ILI method are:

- Applicability to long sections of pipeline

- The ability to retrieve and compare previously logged data for corrosion trending
- The transferability of data to geographic information system (GIS)
- The non-destructive nature of the tools

7.3.1.1 Internal and External Corrosion Categories

ILI is used to detect metal loss; the appropriate metal loss tools are:

- Magnetic Flux Leakage, Standard Resolution
- Magnetic Flux Leakage, High Resolution
- Ultrasonic Compression Wave
- Ultrasonic Shear Wave
- Transverse Flux

7.3.1.2 Stress Corrosion Cracking Category

ILI method is used to detect cracks; the appropriate crack detection tools are:

- Magnetic Flux Leakage (MFL)
- Ultrasonic Shear Wave
- Transverse Field Inspection (TFI)
- Electro Magnetic Acoustic Transducer (EMAT)

7.3.1.3 Third-Party Damage/Mechanical Damage Category

The ILI method is also used to detect third-party damage; the appropriate tool is:

- Geometry (Deformation) tool

7.3.2 Hydrostatic Pressure Testing

As discussed earlier, the pipeline is filled with water and the pressure is raised to a specified level based on design and service pressure criteria. It is a low-technology technique whose integrity conclusions are relevant only at the time of the test.

Nonetheless, hydrotesting method is appropriate for the following failure types:

- Internal corrosion
- External corrosion
- Stress corrosion cracking
- Manufacturing and related

7.3.3 Direct Assessment (DA)

Direct assessment is a structured process that uses data and information from indirect pipeline surveys and direct examination, along with all other relevant information (e.g., design, construction, and operating data) to assess the pipeline's condition.

It is a four-step process:

1. pre-assessment
2. indirect inspection
3. direct examination
4. post assessment

Each is a non-destructive inspection method to inspect and assess pipelines and flowlines that cannot be pigged or subjected to hydraulic testing.

The available DA methods are applicable to the following failure types:

7.3.3.1 Internal Corrosion

The ICDA method is used for internal corrosion; the tools used for indirect assessment and direct examinations are:

- Flow modeling for corrosion prediction
- Corrosion monitoring
- Ultrasonic Testing (UT) Inspection Technique (non-destructive)
- Radiographic Inspection Technique (non-destructive)
- Camera Inspection (CCTV)

7.3.3.2 External Corrosion Category

The ECDA method is used for external corrosion; the tools used for indirect inspection are:

- Close interval potential survey (CIPS)
- Direct current voltage gradient (DCVG) survey
- Alternating current voltage gradient (ACVG) survey
- Pearson survey
- AC current attenuation (ACCA) survey (an electromagnetic tool)
- Electromagnetic tool

The tool selection matrix for ECDA appears in Table 2.10 on page 77 of Chapter 2.

7.3.3.3 Stress Corrosion Cracking Category

The SCCDA method is appropriate for stress corrosion cracking. The tools used for indirect inspection are similar to those used for external corrosion. For direct assessment, the following tools are used:

- Ultrasonic inspection
- Magnetic particle inspection
- Hydrostatic testing

Chapter 8: Technical Challenges to Pipeline Integrity

After completing this chapter, students should:

- Be familiar with the technical challenges that affect pipeline integrity.
- Understand basic technology behind the technical challenges.
- Know where to find information and guidance to address the challenges.

8.1 Introduction

This chapter addresses technical pipeline integrity challenges faced by the pipeline industry. Technical challenges in pipeline construction, operation and maintenance include:

- Material properties and defects
- Pipe manufacturing
- Pipeline construction
- Pipeline operations and service
- Outside forces
- Time dependent mechanisms (corrosion and cracking)

8.2 Material Properties and Defects

8.2.1 Material Properties

Since its beginnings in the early 1800's, the process of manufacturing pipe used to transport natural gas and hazardous liquid has experienced many milestones. Prior to about 1856, pipe was essentially wrought iron; after that modern steel began to dominate.

Wrought iron is a low grade, ductile steel produced by smelting iron ore. It contains very little carbon and a considerable amount of impurities, such as iron ore slag, from the smelting process. Pipe manufactured from wrought iron is formed by hammering sheets of wrought iron into shape. Wrought iron is relatively corrosion resistant, but has very low toughness and fracture resistance; it has not been used to manufacture pipe in many years and very little wrought iron pipe is still in service. Therefore, wrought iron pipe will not be addressed in this chapter.

Modern steel is a higher grade metal that is much more refined than wrought iron. Modern steels contain fewer impurities and much more carbon than wrought iron. Other materials, such as manganese, are alloyed with iron to produce steel that is tougher and more fracture resistance. Pipe manufactured from modern steel is formed in many ways, but rolled plates and seamless predominate. While modern steel formulations are more suitable to transport natural gas and hazardous liquids at higher pressures, corrosion resistance has declined somewhat.

The steel formulations used for pipes vary widely in their chemical, metallurgical, and physical properties. These properties dictate the pipe's strength, usually referred to as yield strength.

Yield strength is the maximum stress metal can endure before it shows a specified limited deviation from the proportion of stress to strain. The deviation is expressed in terms of strain, percent offset, and total extension under load. (ASTM A370-95 provides details related to yield strength.) To put it simply, yield strength of steel is the maximum stress it can endure before it breaks.

In the pipeline industry, the term used is Specified Minimum Yield Strength (SMYS). SMYS is the minimum yield strength allowed for the various grades of pipe. SMYS is expressed in terms of pounds per square inch (psi). For example, the SMYS for API X52 pipe is 52,000 psi. All API X52 pipe must have an SMYS that equals or exceeds 52,000 psi. Most API X52 pipe will have a SMYS that significantly exceeds 52,000 psi, including pipe with a SMYS approaching the next higher grade, API X60 with a SMYS of 60,000 psi.

Pipes experience stress in two dimensions or directions; axial (along the longitudinal axis of the pipe) and circumferential (around the circumference of the pipe). Steel pipe in typical service conditions seldom experiences axial stresses that approach its yield strength, so axial strength is seldom an issue. Steel pipe in typical service, however, often experiences circumferential stresses that do approach its yield strength, so this is frequently an integrity issue.

8.2.2 Material Defects

Pipe manufactured in the last 20 to 30 years is remarkably free of manufacturing defects because of rigorous manufacturing specifications and production inspections that ensure material quality. Since this has not always been the case, there are many miles of older pipelines in service that may contain defects. Among the primary defects are laminations, inclusions, blisters, and scabs. Definitions of these material defects follow:

- Laminations and Inclusions: caused when oxides or other impurities are trapped in the steel. They form voids or pockets in the pipe wall that can cause failure if oriented in a way that reduces pipe strength. Laminations and inclusions can cause cracks that grow with each pressure cycle until failure occurs.
- Blisters and Scabs: caused by the expansion of trapped gas within the steel. They appear as raised areas on the pipe surface and reduce effective wall thickness as well as pipe strength. Blisters and scabs can cause cracks that expand with each pressure cycle until failure occurs.

8.3 Pipe Manufacturing

Pipe manufacture for use in the oil and gas industries goes back to the early 1800’s. A brief history of advances in pipe manufacture follows:

- Prior to 1812 – hand made hammer lap-weld seam
- 1812 – machine manufactured hammer lap-weld seam
- 1824 – butt-weld or furnace butt-weld seam
- 1836 – machine extruded seamless
- 1840’s – machine continuous lap weld seam
- 1920’s – modern seamless

- 1924 – Low Frequency Electric Resistance Weld (LF-ERW) seam
- 1950's – Submerged-Arc-Weld (SAW) and Double-Submerged-Arc-Weld (DSAW) seam
- 1970 – High Frequency Electric Resistance Weld (HF-ERW) seam

Most of the pipe in use today was manufactured after about 1920 by the following processes:

- Lap-Welded Longitudinal Seam
- Flash-Welded Longitudinal Seam
- Electric Resistance Weld (ERW) Longitudinal Seam
- Submerged Arc Weld (SAW) and Double Submerged Arc Weld (DSAW) Seam
- Spiral Weld Seam
- Seamless

8.3.1 Lap-Welded Longitudinal Seam Pipe

Lap welding started in early 1920s but is no longer used today. Lap-welded pipe was formed by rolling steel sheets heated in furnaces into cylinders. The edges of the sheets were first beveled (called scarfing) to fit against one another then were pressed together using rollers, they were then electric-welded using a welding ball. No filler material was used during welding.

The longitudinal welds of lap-welded pipe have proved to be unreliable in high pressure service because of incomplete weld fusion. If the edges were not heated to sufficiently high temperatures, not pressed together with sufficient pressure, or upsets occurred during the welding process, the fusion was imperfect and weld failure inevitable.

8.3.2 Flash-Welded Longitudinal Seam Pipe

Flash welding started in the middle to late 1920s, but is no longer used. Flash-welded pipe, like lap-welded, was formed by rolling steel sheets heated in furnaces into cylinders. The edges were cut square, heated until semi-molten, and the heated edges forced together until the molten steel fused. The excess molten steel was forced out of the joints to form beads. Most flash-welded pipe was made by the manufacturer, A.O. Smith.

Just as with lap-welded seams, the longitudinal welds of flash-welded pipe have been problematic because incomplete fusion and weld failures occurred if the sheet edges were not heated hot enough, the edges not pressed together with sufficient pressure, or if upsets occurred in the edge joining process. Additionally, the seams were and are susceptible to corrosion and hook cracks.

8.3.3 Electric Resistance Weld (ERW)

Electric resistance welding began in the middle 1920s. The pipe is formed by cold rolling steel sheet into cylinders; an electric current is passed between the edges of the sheets to heat them, and pressed together to form the longitudinal seam. No weld filler is used in this process.

Electric resistance welded pipe has had a good reputation with one major exception; pipe manufactured before 1970 used low frequency AC current welding. It is referred to as Low Frequency Electric Resistance Welded (LF-ERW) pipe. Low frequency welding was susceptible to welding upsets that caused incomplete fusion and voids along the weld seam resulting in inadequate bonding. This made the seams vulnerable to selective seam corrosion and hook cracking. LF-ERW pipe is no longer made.

In 1970, pipe manufacturers began using High Frequency Induction heating to weld steel plate edges together. The longitudinal seam of High Frequency Induction Electric Resistance Welded (HFI-ERW) pipe is far superior to the seams of LF-ERW pipe. The HFI-ERW seams are not susceptible to selective seam corrosion or hook cracking. Other advancements in manufacturing improved the quality of the longitudinal seam even further in the 1980s. HFI-ERW pipe is still in production today.

8.3.4 Submerged Arc Weld (SAW)

Submerged arc welding in pipe manufacture began in the 1950s and is still in use. Steel sheets are cold rolled into cylinders and the edges arc welded together. First the edges are beveled, then the beveled areas are filled during the arc welding process. Filler metal for the welds is provided by electrodes. The welding arc is submerged under flux during welding.

Submerged arc welding can be done only on the external side of the pipe or on both the exterior and interior of the pipe. Exterior only welding is called Single Submerged Arc Welding (SSAW) and is done against a backing shoe placed on the interior surface. Welding done on both the exterior and interior of the pipe is called Double Submerged Arc Welding (DSAW). DSAW welding penetrates 100% of the pipe wall and produces a very strong bond.

8.3.5 Spiral Weld

Spiral welding has been done since the 1880s, but modern spiral weld pipe production starting in the 1960s. Spiral weld pipe is still being manufactured and has gained popularity in recent years.

Steel sheets or strips are wrapped in a spiral around a mandrel of the appropriate diameter and then the edges are joined either by electric resistance welding or submerged arc welding. Submerged arc welding is preferred, and may be the only acceptable, joining technique used today. Submerged arc welded spiral weld pipe is susceptible to the same seam defects as longitudinal seam submerged arc welded pipe.

8.3.6 Seamless

Manufacture of modern seamless pipe began in the 1920s. With increased demand for pipe by the oil and gas industry in the 1920s and 1930s, manufacture of seamless pipe expanded tremendously. It had better strength and reliability than welded pipes. Seamless pipe is still being utilized today.

It is made by forcing plates or billets of steel over shaping or piercing tools. For the most part modern seamless pipe has and is being manufactured using two mill techniques: plug and mandrel.

The plug technique is used to form larger diameter pipes, usually six inches or greater. A heated ingot is pierced, the pierced hole enlarged by a rotary elongator, and then a plug is forced through the pipe to produce the desired inside diameter. The pipe with the plug in place then passes through rollers to reduce the wall thickness to the desired thickness. Finally, it is passed through both a reeling mill and a reducing mill to even out wall thickness and reach the finished dimensions.

The mandrel technique is used to manufacture smaller diameter pipe, usually six inches or less. A heated ingot is pierced and then a mandrel and curved rollers, in a continuous process, shape the pipe to its approximate wall thickness and diameter. The pipe then passes through a reducing mill to reduce the wall thickness and diameter to the finished dimensions.

Because seamless pipe does not have a longitudinal seam, it is not susceptible to long seam defects. It is, however, susceptible to defects from impurities in the steel. While this is not a significant problem with seamless pipe being manufactured today, difficulties from impurities in the steel have not been totally resolved.

8.3.7 Pipe Manufacturing Integrity Challenges

Pipe manufacturing materials and techniques have improved greatly over the years and while pipes manufactured today may have some flaws, they are essentially defect-free. In this regard, a flaw is defined as an imperfection that does not affect serviceability; a defect on the other hand, contributes materially to failure or limited serviceability. Most pipelines in operation today were constructed with pipe manufactured between 1920 and 1970. They are generally not defect-free. Consequently, for reasons discussed previously in this chapter, failures caused by faulty pipe manufacturing can occur. While these failures account for less than one percent of all pipeline failures, any such failure can be catastrophic. Primary integrity challenges related to pipe manufacturing include:

- Hard spots
- Defective longitudinal seams
- Mill anomalies

8.3.8 Hard Spots

Hard spots are areas of pipe significantly harder than surrounding areas; the degree of hardness is greater than allowed by pipe manufacturing specifications. Although not common, hard spots have caused pipeline failures. Some of failures have been leaks, but the failures are usually ruptures.

Hard spots that result in failures typically occur on flash weld seam pipe manufactured in the 1950s by A.O. Smith. These hard spots are not related to the flash weld seam, but rather were caused by non-uniform water quenching of the pipe plate during the rolling process.

Hard spots in themselves do not cause failures. The failure mechanism at hard spots is always cracking; usually hydrogen stress cracking. Hydrogen stress cracking requires steel of sufficient hardness and strength, sufficient sustained tensile stress and the presence of atomic hydrogen. The source of atomic hydrogen is probably from the cathodic protection process. The pipes fail in a brittle mode.

Two techniques are used to detect hard spots: hydrostatic testing and inline inspection. Descriptions and limitations of these techniques are below:

- Hydrostatic testing will find hard spots if cracking exists at the hard spots and if the cracks have grown sufficiently to weaken the pipe. This usually happens years and years after pipeline construction. Initial construction hydrostatic testing did not find the hard spots because there had not been sufficient time for cracking to occur. The only possible remediation for hard spots found by hydrostatic testing is pipe replacement.
- Specialized “hard spot detection” inline inspection tools are available. The tools use magnetic flux leakage (MFL) to detect hard spots. (Hard spot detection tools differ significantly from standard “metal loss detection” MFL tools that will not detect hard spots.) These tools detect only the hard spots and not cracking associated with hard spots. Remediation of hard spots found by inline inspections is accomplished by replacing the pipe or by installing reinforcement sleeves. It is advisable to repair all significant hard spots even if there is no cracking because the potential for future crack development and growth is considerable.

8.3.9 Defective Longitudinal Weld Seams

Failure to fully fuse the metal along the weld line of pipes would normally result in defective longitudinal weld seam that appears as a linear groove or crevice running along the pipe. All major welding codes allow for weld-seam defects, but set limitations on the severity of such defects. An acceptable weld seam is not one that is defect free, but one in which its defect does not prevent satisfactory service. Weld-seam defects may be due to faulty fabrication methods of steel rolling in the steel mill, porosity, slag inclusions, excess penetration, incomplete fusion, undercut, inadequate joint penetration, cracking, and possible graphitization.

Like hard spots, defective longitudinal weld seams have caused pipeline failures. However, the percentage of failures that occur solely from all defects (including weld-seam defects) is less than 1% of all failures. Weld-seam failures tend to be opportunistic; failure occurs when a weld seam acts in concert with specific environmental factors. The failures in some cases have been leaks, but most are ruptures, aided by mechanical fatigue, thermal fatigue or any combination of the various time-dependent corrosion mechanisms.

The two techniques, described above for detecting hard spots (hydrostatic testing and inline inspection) can also be used to detect defective longitudinal weld seam. Another useful nondestructive testing technique for detection of weld-seam defects is ultrasonic testing.

8.3.10 Mill Anomalies

Other than manufacturing defects previously discussed, most other manufacturing defects are classified as mill anomalies; they are usually not injurious to pipe integrity. These include minor/tight laminations, trapped impurities, slag, rolled-in slugs, slivers, and manufacturing marks such as mandrel marks. Even though these mill anomalies are not normally injurious, during inspection they can cause signification problems. Inline inspection or non-destructive instruction methods (e.g., ultrasonic inspection) show defect indications that are often difficult to evaluate. Unfortunately, until better inspection techniques are developed, pipeline operators will have to deal with mill anomalies as they are detected.

8.4 Pipeline Construction

Pipeline construction challenges that can lessen pipeline integrity include:

- Poor construction practices
- Construction stresses
- Bedding and backfill
- Long term soil stresses
- At-grade external loads
- Temperature expansion and contraction
- Inadequate documentation

8.4.1 Construction Stresses

Each pipe section undergoes rigorous quality control at the mill; yield strength, wall thickness, metal chemical composition, cooling, etc., are carefully monitored to meet required specifications and manufacturing tolerances.

Mill applied coatings undergo similar quality control procedures. The pipe is grit blasted, cleaned, and prepared for the coating application. Coating is applied by mechanical equipment under controlled conditions.

Once the pipe leaves the manufacturing facility, however, it can be subjected to stresses and damage caused by transportation (loading and unloading) cutting, and welding. All these activities can generate residual stresses or damage to the pipeline's metallurgical structure, not to mention damage to the protective coating. The following are the problems and challenges of post construction stresses:

- Transportation (Loading/Unloading): Lifting the pipe with slings (for loading and unloading) creates bending stresses in the pipe. Coating damage can occur during transportation if not handled properly. To reduce such stresses and coating damage, several slings are normally used to lift the pipe onto the truck or rail car. This reduces the bending stresses on the pipe. It should be placed on soft pads (rubber, etc.) to prevent damage to the coating.

- Cutting and Welding: Other than the obvious coating damage caused by cutting and welding, they change the metallurgical structure of the metal altering its corrosion characteristics, especially in heat affected zones near welded areas.
- Wrinkle Bends: This was a popular method used in the past; the pipe was bent and wrinkles are formed on the internal side of the bend. This engendered a lot of residual stresses on the external side of the bend. This are was subject to more accelerated corrosion than other sections of the pipe given the same conditions.

The challenge is to reduce construction and post construction stresses to a minimum. With careful handling, and development of sound procedures to handle and construct the pipe, these stresses can be made minimal and non-detrimental. For older extant pipelines, identifying the effects of these stresses is much more complicated. In-line inspection tools are used to find metal loss at some wrinkle bends, girth welds, dents, and gouges; engineers can use the data collected to determine if corrective action is needed.

8.4.2 Bedding and Backfill

Older pipelines are normally backfilled using the same soil excavated from the trench. The excavated soil was rarely sieved to remove rocks, or other material that could damage the coating or add local stresses on the pipe. The pipe was probably placed right on native soil, which creates several problems: the soil around the pipe contains more oxygen than soil beneath it. This causes differential aeration corrosion as the bottom of the pipe becomes more anodic initiating pitting. The other problem is more stress related. If the pipeline is placed on rock, coating damage and local concentrated stresses are created. It is not unusual to find dents and gouges at the bottom of the pipe; these circumstances create concentrated stress risers that can greatly affect the integrity of the pipe.

In recent years, uniform bedding and backfill have been used to alleviate such problems. Backfill can be imported from off-site if the soil in the area cannot be seived properly to remove rocks and debris. In addition, rock shields are used more frequently during backfill to prevent damage to the coating.

The challenge is to identify the type and composition of existing pipeline backfill. This is not easily accomplished since older pipelines did not use uniform backfill. Newer pipelines have construction drawings and specifications available for review so the type of backfill can be identified.

8.4.3 Long Term Soil Stresses

Long-term soil stresses play an important role in pipeline integrity; they can create significant coating damage. The dry/heave action of soil generates tremendous stresses that can cause several mechanisms to damage coatings: cracking, spalling, disbondment, tearing, and wrinkling. So, the effects of soil stresses are significant to pipeline integrity. For example, stress corrosion cracking can be found under disbonded coating that shields the cathodic protection current from reaching the steel surface.

Technology has not yet found a reliable way to detect soil stress related coating damage. If the coating is already cracked, over the line surveys can detect and pinpoint the location of exposed steel. However, if the coating is simply disbonded, over the line surveys cannot always detect it. Research is underway to develop a reliable in-line inspection tool that can also detect disbonded coating. A prototype tool has showed promise in detecting disbonded coal tar coatings, but more research and technology is needed to make the tool reliable in detecting damage for any type of coating.

8.4.4 At-Grade External Loads

External loads can impose bending stresses on pipelines. Stresses from external loading also depend heavily on the depth of the pipeline. The deeper the line, the fewer the external load stresses. Examples of external loading are:

- Trucks
- Trains
- Water crossings; a pipeline under a river may undergo more stresses than pipeline on shore
- Bridge crossings; bridge vibration and wind loading can be significant

Determining the exact stresses caused by such loading is difficult, and even more difficult is understanding what effect, if any, such loading has on pipeline integrity.

Cased crossings are an area of special interest. The pipe inside the casing is not overburdened with soil (no soil related stresses) but the pipe outside the casing can experience overburden pressure. Differential loading at both ends may cause a bending effect on the pipe in the casing, the effect of which has not been thoroughly evaluated.

8.4.5 Temperature Expansion and Contraction

Temperature variations are most prevalent at gas compressor and liquid pump stations. Temperatures on the discharge side of a compressor station can reach 135°F (57.22°C) and higher. The elevated temperatures can have a significant effect on pipeline integrity, i.e., cathodic protection current requirements increase as temperature increases; coating damage can result from temperatures exceeding the manufacturer's recommendations. The combination of elevated temperature, increased cathodic protection current needs, stress increases or fluctuations can all combine to initiate and sustain stress corrosion cracking.

Expansion and contraction caused by temperature variation can also affect the integrity of pipeline coatings; pipe coating adhesion can be materially lessened by cyclical stresses and constant temperature variations. Physical inspection and adhesion testing are needed to evaluate this threat.

8.4.6 Inadequate Documentation

Information related to design, construction, operation and maintenance of pipelines is fundamental to integrity management. Without accurate and reliable information, evaluating pipeline integrity is difficult and requires considerable initial effort to obtain the information needed for the evaluation. Pipeline operators frequently discover that they have inadequate information when, during pipe inspections, they find conditions other than that expected from evaluation of their available information.

Reasons documentation may be sparse or lacking:

- In the early years, many construction decisions were made on site during construction. These decisions and the factors that informed them were not documented because the emphasis was on completing construction.
- When pipelines have had a single operator for many years, documentation can be lost as employees retire, pipeline areas are reassigned, field offices moved, and/or other changes in personnel and locations.
- Change of ownership is perhaps the greatest cause of lost documentation. Unfortunately, often large amounts of information are not transferred to the new owner.

It is imperative that pipeline operators do everything within their power to identify, gather and protect integrity related information. It should be organized to allow easy access by all operating personnel. A modest investment in information management will be paid back many times over.

8.5 Pipeline Operations and Service

Operation and service conditions that can negatively impact pipeline integrity include:

- High temperatures
- Corrosive contaminants
- Over-pressure stresses
- Cyclic pressure stresses
- Inadequate pressure relief devices

8.5.1 High Temperature

As previously discussed, temperature and temperature fluxuations are parameters that must be understood and evaluated. Elevated temperatures (higher than normal operating temperatures) do not normally occur since monitors safeguard against this, but when an upset occurs, elevated temperature can severely damage the coating, if its tolerance is exceeded. If there is no cathodic protection, the coating damage can allow corrosion to begin. If a slight increase in pressure (hoop stress) accompanies the high temperatures then stress corrosion cracking is very possible.

Maintaining operating temperature within required tolerances is imperative. This can be difficult because when output is increased temperatures may also increase. Therefore, operators need to design and implement procedures to ensure that the pipeline temperature does not exceed the maximum allowable temperature for the pipe and its coating.

8.5.2 Corrosive Contaminants

Chemical spills (even in small quantities and over a long period time) can damage and degrade coatings. Fuel spills or cleaning solutions can deteriorate the coating and expose the pipe to a corrosive environment. This is more prevalent at compressor and pump stations than at pipeline right-of-ways.

Chlorides accelerate corrosion; the higher the chloride concentration and the more aggressive the environment, the more active corrosion can be. Road crossings in frigid northern climates where deicing salts are used become contaminated with chlorides, so the corrosion rate in these areas is higher. When combined with oxygen (which controls the reduction reaction at the cathode and effects the corrosion rate), contaminants can make a very difficult environment in which it is quite difficult to control corrosion.

Operators must identify sources of contaminents, and understand thoroughly how they accelerate corrosion in order to design counter measures to combat them.

8.5.3 Over-Pressure Stresses

Pipelines generally operate below Maximum Allowable Operating Pressure (MAOP). When MAOP is exceeded, Over Pressure Protection (OPP) devices such as pressure relief valves are used to reduce the pressure.

However, during the short period of time until all OPP devices engage, the pipeline may be subjected to damaging higher stresses. These stresses are much more acute at stress risers (i.e., dents, gouges, scratches, laminations, and cracks). Even though most pipelines operate at less than 72% of Specified Minimum Yield

Strength (SMYS), it is possible to approach SMYS during brief periods of over pressure; this can propagate cracks.

Conversely, over-pressure is used to test for pipeline operational integrity. Hydrostatic testing verifies pipeline integrity by over-pressuring the pipeline to 100% – 120% of SMYS. Hydrostatic testing, its use, and its benefits are discussed later in this chapter.

8.5.4 Cyclical Pressure Stresses

Unlike periods of over-pressure that occur infrequently, cyclical pressure variations are a daily part of pipeline operation. These variations are more intense in hazardous liquid pipelines near pump stations than natural gas pipelines in which pressure normally does not vary by more than 5%.

For that reason, cyclical stresses are more of a concern on hazardous liquid lines. Continual expansion/contraction of the pipeline can lead to fatigue failure and plastic deformation of the metal at stress risers.

Cyclical stresses can also initiate and propagate stress corrosion cracking. Stress Corrosion Cracking (SCC) will be discussed later in this chapter.

8.5.5 Inadequate Pressure Relief Devices

Pressure relief devices are designed to open and relieve the pressure in a pipeline when a certain pressure is reached or exceeded (normally slightly higher than MAOP). These safety devices are crucial in relieving over-pressure and preventing pipeline failure.

If pressure relief devices are inadequate or too few in number, the pipeline can experience over pressure events that can have an impact on the pipeline (which as discussed previously) and can compromise pipeline integrity.

8.6 Outside Forces

Outside forces that can compromise pipeline integrity are acts by man and forces of nature. Since outside forces are extremely difficult or impossible to predict, preventive steps are tricky to formulate. The challenge is to identify steps to minimize impact after the damage occurs. This section addresses specific integrity challenges resulting from outside forces.

8.6.1 Acts of Men

Acts of men that can damage pipeline integrity generally fall into these categories:

- Construction damage
- Operator damage
- Third party damage (accidental or intentional)
- DC and AC electrical interference from outside sources

8.6.1.1 Construction Damage

Gouges, dents, and coating damage occur on pipelines during construction as a result of improper pipe handling, improper ditch preparation, lack of adequate padding, debris in backfill, and improper joint coating. These construction defects are very susceptible to external corrosion.

With detailed construction specifications, strict inspection during and after construction, and training for construction and inspection personnel, construction damage can be minimized or even eliminated.

8.6.1.2 Operator Damage

Operator damage is unintentional damage caused the pipeline operating personnel; it is not common, but it does occur. Operator damage includes improper operation (i.e., over pressuring facilities by closing or opening valves that should not have been closed or opened) and mechanical damage (i.e., hitting pipes with equipment and/or tools that damage it or its external coating).

Operator damage is one of the few integrity threats that can be controlled and very nearly eliminated by operators who have good procedures and practices, and thorough employee training and supervision.

8.6.1.3 Third Party Damage

Studies have shown that third party damage is one of the leading causes of pipeline rupture and failure, particularly unintentional damage by earth moving equipment. The damage can be either scratches, dents, or gouges (which concentrate stress as well as damage coating), or worse, ruptures which can lead to loss of life.

The One-Call line locating system is crucial to locate, flag, and alert third parties to the existence of underground pipelines. Unfortunately, accidents do still happen and many operators take extra measures to improve their line locating procedures and processes. Training construction personnel to thoroughly understand line markings is one of the best ways to prevent third party damage.

The One-Call system and operator training must be constantly improved to greatly minimize or eliminate third party damage. One incident is one too many.

8.6.1.4 DC and AC Electrical Interference

Electrical interference can be from either DC or AC stray currents.

DC interference can be very detrimental to pipelines. Sources are cathodic protection systems, DC powered transit rail cars, DC powered rail cars in mines, high voltage DC transmission lines, large welding shops, or any other nearby source of DC current.

AC interference is found near high voltage AC power lines whose steady state and fault voltages are induced on the pipeline resulting in stray currents. These can not only inflict serious shocks on personnel, but can also cause corrosion failures from AC current densities where pipe coatings are damaged.

If DC and AC interference can be found, they can be controlled and mitigated. Operators have to find the interference and its source, then devise the best mitigation measure. Since DC interference can change its intensity and magnitude unpredictably due to increased output from foreign rectifiers, newly installed foreign rectifiers, newly installed DC rails, etc.), it is vital for pipeline operators to have plans and procedures to regularly monitor existing interference, as well as collect data to identify new threats.

8.6.2 Forces of Nature

Forces of nature that can severely damage pipeline integrity are:

- Earthquakes
- Earth slips and mud slides
- Erosion and flooding
- High winds
- Telluric electrical interference
- Extreme temperatures

8.6.2.1 Earthquakes

Earthquakes are capable of inflicting catastrophic damage to pipelines (particularly ruptures) since they can involve tremendous ground movement over large areas. Automatic valves and other safety devices simply cannot react quickly enough to forestall sudden drops in pressure when one or multiple ruptures occur on a pipeline. Needless to say, ruptures cause devastating harm to people and facilities.

During pipeline design and construction, measures such as automatic flow routing and more numerous automatic shut off valves in fault areas can be built in to minimize damage from earthquakes. However, even the best measures and most exacting preventive steps cannot protect pipelines from damage caused by major earthquakes.

8.6.2.2 Earth Slips and Mudslides

Large amounts of earth slipping or sliding down hills, mountains, or canyon walls are called “earth slips” or “mud slides” and are caused by unstable soil that occurs either naturally, from disturbance by man (such as during pipeline construction), or by heavy rains and flooding. Regardless of the mechanism, slips and slides can leave significant lengths of pipeline exposed and inadequately supported; in extreme cases, the unsupported pipe can break.

8.6.2.3 Erosion and Flooding

Erosion damage that undermines pipeline support and expose the pipeline to outside forces is of significant concern to operators. Erosion in those areas means the pipeline is no longer supported and the stresses change in the exposed area, as well as at both ends where soil still supports it. Another concern is the fact that the pipeline is then exposed to ultraviolet rays (which can degrade some coatings), as well as third party damage. Aerial surveillance of the pipeline is an excellent way to detect erosion damage in remote areas. Prior to re-burying the pipeline and restoring the surface, the technicians and maintenance crews should inspect it thoroughly and make any necessary repairs.

8.6.2.4 High Winds

Quite often pipelines cross highways and rivers suspended on bridges or other aerial structures; these structures sway during high winds. The swaying of the structure produces stresses and strains on the pipeline that can damage it if the movement is excessive.

8.6.2.5 Telluric Electrical Interference

Sun spot activities and the earth's magnetic fields generate telluric currents on pipelines. These currents can make collecting reliable pipe-to-earth potential measurements very difficult. Telluric currents are more pronounced near the north and south poles. For example, transmission pipelines in Alaska are frequently subject to telluric currents, so special measures and techniques are used to collect reliable potential measurements.

Research into telluric current corrosion of pipelines caused by telluric currents is still in its infancy. Whether telluric currents create severe corrosion on cathodically protected pipeline is still being studied and researched.

8.6.2.6 Extreme Ambient Temperatures

Extreme ambient temperatures can affect the integrity of a pipeline in several ways. Coatings are designed to provide protection in a wide temperature range, but extremely cold or hot temperatures can severely degrade the coating's ability to perform as designed. Cracking and disbondment occurs in extremely cold temperatures, while disbondment and wrinkling occurs in extremely hot temperatures.

Extremely hot temperatures require a much higher cathodic protection current density to provide effective protection to the pipeline. Protection criteria for pipelines are normally developed for ambient temperatures of approximately 25°C (77°F); it has been suggested that the cathodic protection criteria for hot metal surfaces be adjusted. Some suggest an increase in potential criteria of 2mV/°C (1.11mV/°F) to compensate for the hot temperatures. The Appalachian Underground Corrosion Short Course's Intermediate Level text, written by J. A. Beavers and K. C. Garrity, states that current requirements can increase by a factor of 2 for every 10^{o}C (18^{o}F) increase in pipe temperature. It also states that a potential of -950 mV with respect to Cu-CuSO4 should be used for hot pipelines.

Another problem for pipelines in extremely cold climates is insulation. Pipe is insulated to permit the product to flow more freely and more efficiently. However, corrosion underneath pipe insulation is well documented; so measures are needed to mitigate or greatly reduce this threat. The challenge is to develop a material that provides excellent insulating properties and prevents corrosion at the insulation/pipe surface interface.

8.7 Time Dependent Mechanisms

Time dependent mechanisms affect the mechanical properties of the pipe steel with time. The primary time dependent mechanisms are:

- External corrosion
- Internal corrosion
- Stress corrosion cracking

8.7.1 External Corrosion

External corrosion is deterioration of metal caused by an electro-chemical reaction of the pipe steel with its environment. External corrosion can occur on pipe buried in soil, submerged in water or exposed to the atmosphere. Pipe is subject to external corrosion when its environment is corrosive and an external protective coating has not been applied or is not completely effective. External corrosion is, with only a few exceptions, not dependent on the product being transported or on operating parameters.

This chapter deals primarily with external corrosion on buried or submerged pipelines. Since we addressed external corrosion earlier in this course, this chapter deals more particularly with corrosion stemming from:

- Shielding coatings
- Shielding coating flaws
- Non-shielding coating flaws
- Inadequate cathodic protection
- Cased carrier pipe

8.7.1.1 Shielding Coatings

When a coating disbonds from the pipe, but is still intact (no cracks or breaks), the coating can prevent the cathodic protection current from reaching the steel surface. Shielding is more pronounced with some coatings than others, but when a disbonded coating interferes with the cathodic protection current, corrosion can occur and progress under the coating wherever water can accumulate. Disbonded coatings have also been known to permit stress corrosion cracking to initiate and propagate. Without cathodic protection (which can increase the pH at the metal surface to 9, 10, or 11), corrosion can advance, and in the presence of stress cracking, can cause stress corrosion cracking colonies to form and expand.

As previously discussed, some pig manufacturers have developed prototype in-line inspection tools to try to detect disbonded coatings. Limited success has been reported and more advancement in technology and research are needed.

8.7.1.2 Shielding Coating Flaws

A flaw in the coating allows water and contaminants to migrate behind the coating if the coating is disbonded around a flaw. There is some cathodic protection at the flaw where the metal is in contact with the soil, but due to shielding, there is no protection where the coating has disbonded. In those areas, corrosion can occur and proceed unabated.

8.7.1.3 Non-Shielding Coating Flaws

As long as the coating is bonded around a flaw, cathodic protection current can reach the surface of the steel around the holiday and protect the metal from corrosion. Over-the-line potential surveys should be used periodically to verify that the steel is being cathodically protected effectively.

8.7.1.4 Inadequate Cathodic Protection

External corrosion can be mitigated with adequate cathodic protection. However, if protection levels do not meet applicable protection criteria, corrosion can occur (albeit at a reduced rate). Even with the corrosion rate reduced several fold, with time, corrosion at inadequately protected locations has resulted in pipeline failure.

Data collection is thus a critical factor to ensure the pipeline is being cathodically protected. Cathodic protection system monitoring, cathodic protection surveys at fixed test stations and close interval potential surveys can be used to determine if the pipeline is protected, and more importantly, to identify cathodic protection deficiencies that require remedial action.

Cathodic protection testing is not foolproof. The data must be properly collected and analyzed. Precautions to take when collecting data include:

- Ensure the reference electrodes are clean and calibrated;
- Ensure the meter has been recently calibrated;
- Check that the insulation of the test lead wires is intact;
- Consider IR Drop when taking potential measurements;
- If current interruption is used to eliminate IR drop error, several further precautions must be taken:
  - **All** company current sources influencing the pipeline must be interrupted;
  - **All** foreign current sources influencing the pipeline (i.e., through bonds) must also be interrupted;
  - **All** interrupters must be synchronized; GPS synchronizable interrupters are ideal for such application;

- The **ON** and **OFF** interruption cycle must be chosen to provide the most accurate data, while minimizing depolarization of the pipe caused by continuous current interruption;

- If disbonded coating is shielding the pipe from the soil, potential measurements will not be able to locate and identify this irregularity;
- Potential measurements in stray current areas can be erratic and meaningless;
- Surface potential measurements cannot measure the potential of the pipe inside a cased crossing; and
- Potential measurements taken in a congested corridor may not be accurate; the measurement displayed on the voltmeter may be an average of all the pipelines in the corridor at that test location (if the pipelines are electrically continuous).

Once the data is collected, it must be analyzed by an experienced corrosion professional to ascertain the effectiveness of the cathodic protection system, and to identify areas that require attention. These areas can be irregularities that must be monitored, or deficiencies that must be remedied.

NACE SP0169 (latest version) states that effective protection is achieved if the following criteria are met:

- A negative (cathodic) potential of at least 850 mV with respect to a $CuCuSO_4$ electrode with the cathodic protection applied and with voltage drops other than those across the structure-to-electrolyte boundary considered for valid interpretation of the measurement;
- A negative polarized potential of at least 850 mV relative to a saturated $CuCuSO_4$ electrode; and
- A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.

These criteria must be applied while keeping in mind:

- Criteria are based on IR drop free potential measurements;

- Criteria are developed under normal ambient conditions. Deviations from such conditions must be taken into consideration when applying potential criteria;
- If microbiologically induced corrosion activity is confirmed, a more negative potential then -850 mV is required; and
- Avoid using the 100 mV criterion under conditions of high temperature, stray current areas, telluric current areas, mixed dissimilar metal areas, or stress corrosion cracking conditions more positive than -850 mV.

As the pipeline network ages and the original applied coatings continue to degrade, cathodic protection current requirements will continue to increase. Additional cathodic protection systems will be required as CP current requirements increase. Re-coating the entire pipeline is feasible, but expensive. Historically operators have applied more cathodic protection as coating deteriorates, while strategically recoating sections of piping that are difficult to protect or are in critical areas (such as HCA areas).

8.7.1.5 Cased Carrier Pipe

Detecting and mitigating external corrosion of a carrier pipe inside a casing has been a perplexing challenge for pipeline operators for many years. The historic data of cased carrier pipe failures indicate that cased carrier pipe is only slightly more likely to fail because of external corrosion, than unencased carrier pipe. However, because of a few high profile failures of cased carrier pipe, its integrity has been given a lot of attention by regulators. Consequently, regulations require pipeline operators to take extra measures to ensure integrity of cased carrier pipe.

The corrosion mechanism of the pipe inside the casing depends on several factors such as electrical isolation between carrier pipe and casing, as well as the environmental conditions inside the casing (dry or wet).

Casing Electrically Isolated From Carrier Pipe – Casing Is Dry

If the casing is electrically isolated from the carrier pipe, and the casing is dry (no mud or water in the annular space), the pipe is subject only to atmospheric corrosion at coating holidays. A good coating is the best corrosion control measure for the pipeline in this case.

Casing Electrically Isolated From Carrier Pipe – Casing Is Wet

If the casing end seals fail, and the casing fills with mud and water, corrosion of the carrier pipe at coating holidays is likely. The casing shields the pipe from the full beneficial effects of the cathodic protection. However, research has shown that the encased pipeline receives some protection, which slows down the pipe's corrosion rate. Some theorize that since the casing is isolated from the pipe, it becomes part of the conductive media (the soil) and is able to provide some current to the casing.

Some theorize that the cathodic protection current in the soil outside the casing causes a potential difference between the exterior and the interior surfaces of the casing, which is how current is generated. Small currents leave the interior surface of the casing, flow through the water/mud inside the casing, collect on the pipeline and thus provide the pipeline with small, beneficial cathodic protection currents. Depending on the quality of the coating inside the casing, these beneficial currents can significantly reduce the corrosion rate at coating holidays. It is very important to keep the number and size of defects in the coating inside any casing to an absolute minimum.

Casing Electrically Shorted To Carrier Pipe – Casing Is Dry

Since the casing is electrically continuous with the carrier pipe, the cathodic protection current will collect on the casing and flow directly back to the pipe at the point of electrical contact. The pipe inside the casing will undergo atmospheric corrosion and a good coating is required to control atmospheric corrosion.

Casing Electrically Shorted To Carrier Pipe – Casing Is Wet

In this case, any current collected on the casing will flow to the pipeline through the metallic contact. No protection is afforded to the pipeline inside the casing. Furthermore, galvanic corrosion may occur as the coated carrier pipe is now electrically connected to the casing (uncoated internal surfaces) with a common electrolyte (mud and water). If an area of the pipe becomes anodic to the casing, corrosion will occur and pitting on the pipe may result.

A big challenge for pipeline operators is how to test the pipe inside the casing. Since surface potential measurements cannot measure the potential of the pipe inside the casing, few options are available to determine the integrity of the cased pipe. If the pipeline is piggable, inline inspection tool logs are extremely valuable to determine if corrosion exists, and what are the depth and width of the corrosion indications. However, if the pipeline is not piggable, it is very difficult to determine the integrity of the pipeline inside the casing.

Since regulations require pipeline operators to take extra measures to ensure integrity of cased carrier pipe, they have been quite interested in the new technologies that try to assess existing corrosion on encased pipe. Guided Wave technology has shown promise, but the technology is in its infancy; on-going technological improvements are needed to make it a viable and reliable tool. Operators have also opted to use inert material to fill the annular space between the pipe and the casing, such as hot waxes, casing fillers, inhibitors, etc. Some operators have a program to “sniff” the vents using gas detection equipment; but the problem remains the same – inspection, maintenance, and general pipeline integrity activities for cased carrier pipe are generally very difficult and expensive, and so are dealt with on a case-by-case basis.

8.7.2 Internal Corrosion

Internal corrosion is deterioration of the internal (interior) surface of a pipe caused by electrochemical interaction of the steel with corrosive contaminants inside the pipe. Pipe is subject to internal corrosion when a transported product itself is corrosive or when a non-corrosive transported product contains water or another electrically conductive liquid. Internal corrosion is highly dependent on the product being transported and on operating parameters. Because we have addressed internal corrosion earlier in this course, this chapter deals primarily with internal corrosion caused by corrosive contaminants in transported product.

The variety of products transported by pipelines have similar internal corrosion mechanisms with subtle, but noteworthy differences. The following are the four primary categories of pipelines based on transported product.

Dry Gas Pipelines

Dry gas pipelines transport gas that is dry under normal pipeline operating conditions. However, in some cases water and other unwanted corrosive contaminants are inadvertently introduced into them. Cross country transmission pipelines are usually dry gas.

Wet Gas Pipelines

Wet gas pipelines transport unprocessed natural gas that often contains significant quantities of water in either vapor and/or liquid phase as well as other corrosive contaminants. Production field gathering lines are normally wet gas.

Crude Oil Pipelines

Crude oil pipelines transport unprocessed or minimally processed crude oil. It may contain corrosive contaminants such as water and hydrogen sulfide.

Refined Products Pipelines

Refined products pipelines transport refined or processed petroleum, or chemical products such as motor fuels and manufacturing chemicals. The refined products are normally non-corrosive and free of any significant quantities of corrosive contaminants. Sometimes, however, the refined products can be corrosive or have unwanted corrosive contaminants inadvertently introduced into otherwise non-corrosive refined product.

No matter the type of pipeline service, there are basically five (5) actions that pipeline operators can take to control internal corrosion:

1. Use precise, specific contract language in product purchase, exchange, and transportation agreements to prevent or limit introduction of water and corrosive contaminants.
2. Monitor product closely for water and/or corrosive contaminants that exceed contract limits, and refuse to receive out-of-contract product.

3. Implement cleaning pig programs to remove free water and corrosive contaminants from pipelines.
4. Treating pipelines with corrosion inhibitors and bactericides to prevent internal corrosion.
5. Conduct specialized investigations (i.e., In-Line Tool Inspection and Internal Corrosion Direct Assessment) to identify internal corrosion damage.

8.7.3 Stress Corrosion Cracking (SCC)

Stress corrosion cracking occurs at stresses below the metal's ultimate tensile strength, usually as a result of the combined action of stress and a corrosive environment. Characteristics of SCC:

- Stresses are constant or slowly varying
- A failure may take several hours or many years to occur
- Cracks exhibit little, if any, ductility
- Mechanisms may vary for different material/environment combinations

There are three factors that contribute to SCC: metallurgy, environment, and stress. All three factors must be present to cause SCC. The metal must be susceptible to SCC under certain conditions, stresses must be present, and a corrosive environment must exist. These will be discussed in more detail below.

There are two types of SCC: High pH SCC and Near Neutral pH SCC. Their histories and characteristics follow:

8.7.3.1 High pH SCC

- It was first identified in March, 1965 after a pipeline failure in Natchitoches, LA.
- In 1966, carbonate/bicarbonate environments were found at high pH SCC locations.
- By 1970, the importance of coating condition (type of coating, and disbondment from the pipe) had been studied and was better understood.

- Since 1970, research has unlocked many of the mysteries of high pH SCC. The effect of strain rate, temperature, stress magnitude and stress fluctuations, grit blasting, hydrostatic testing, and many other factors are understood better and, consequently, are used to help identify, evaluate, and repair SCC locations.
- SCC is found mostly under disbonded-tape-coated and asphalt-coated pipe.
- Sodium bicarbonate crystals are normally found at high-pH SCC locations.
- A critical pipe-to-soil potential range has been identified (between -575 mV CSE and -825 mV CSE). Within this range, cracking initiates and grows.
- Temperature has been found to be an important factor; higher temperatures increase crack growth rate, increase the width of the critical potential range, and increase the range of strain rates.
- Cracks are intergranular, small in width, with no corrosion seen at the surface of the crack. Cracks can progress deep into the metal.
- Liquids removed from under coatings where SCC was found include: pH = 9.6-10.5; Carbonate CO_3^{--} 0.5% - 1.4%, and Bicarbonate $H\,CO_3^-$ 0.4% - 0.8%.
- One significant finding is that hydrostatic testing and subsequent retesting is an effective way to assure the integrity of a pipeline with SCC.

8.7.3.2 Near Neutral pH SCC

- This was first generally recognized as a unique causal factor in 1985 in Canada; the first identified failure was in 1975.
- It is found under disbonded field applied asphalt coating and PE tape coating.
- Temperature has not been found to be a controlling factor.
- The potential is generally found to be approximately the open circuit potential of the pipeline.

- Liquids which have been removed from under coatings where SCC was found have pH ~ 6.5 - ~ 8.5.
- White pasty iron carbonate deposits are often an indication of near neutral pH SCC as are extremely bright white deposits found above very shiny metal. The deposits turns green when they are exposed to air and dry to a very fine textureless greenish powder.
- The cracks are quasi-transgranular, wider than high pH SCC cracks, and have corrosion at the surface of the crack. The cracks go less deeply into the metal.
- Hydrostatic testing and subsequent retesting is an effective way to assure integrity of a pipeline with SCC.

8.7.3.3 Detection of SCC

Detecting SCC after the pipeline is exposed for inspection is not very difficult. Once the coating is removed, and the pipe is cleaned slightly (preferably with water pressure blasting since grit blasting can mask the cracks), magnetic particle imaging can be used to find crack colonies. Wet fluorescent or dry powder magnetic particles are typically used by qualified personnel to find cracks. If they are found, a fingerprint is normally taken and calculations conducted to determine the interactive lengths of the cracks. That information is used to determine the needed corrective action (discussed later in this chapter).

Identifying where SCC is present on a buried pipeline is a much more difficult task. There are so many factors and so many interacting variables, that locating exactly where SCC is and how severe it is can be extremely difficult. Surface measurements are ineffective so some inline inspection tools have been developed to locate crack colonies using ultrasonic technology. These tools are very promising and several operators have tested them to locate SCC areas: some reported good success, but others only minimal success. However, research and tool detection hardware are being vastly improved and should, in the near future, yield reliable tools to locate SCC colonies, and, it is hoped, accurately identify the width and depth of each crack.

Because of the lack of reliable, accurate, and inexpensive inline crack inspection tools at this time, particularly when a pipeline is not piggable, engineers must rely on hydrostatic testing or Stress Corrosion Cracking Direct Assessment (SCCDA) methods.

Hydrostatic testing is an effective to test a pipeline for SCC. The pipeline section being tested is filled with water under pressure. The pressure is normally held at ~105% -120% of SMYS. If large SCC cracks are present they will fail and the pipe will rupture. Repairs are then made and the test repeated until no ruptures occur. Hydrostatic testing does not miss large cracks, does not need fully opened valves, smooth bends, or launchers and receivers. However, it is costly, requires a lot of water, environmentally appropriate water disposal, service interruption, can leave small cracks, and since the pressure will vary with elevation it cannot be held equal along the entire section of pipe. Additionally, a retesting interval must be established to ensure continued integrity of the line.

Hydrostatic testing also provides added benefits such as blunting surviving cracks (which may slow or even stop their growth rate), and work hardening the remaining cracks to decrease future creep strain.

SCCDA is a process that helps identify and quantify the SCC threat. The following is a partial list of factors used by the SCCDA process to detect SCC.

High pH SCC

- Pipe information (grade, diameter, year of manufacture, type of weld, and other relevant construction information)
- Operational information (MAOP, temperature, etc.)
- Soil formation and topography (SCC is more often found in clay than sand)
- Operational temperature and fluctuations (higher temperatures increase the risk of SCC)
- Stresses on the pipeline (along with temperature, the highest stress and temperature combination is normally found several miles downstream from the discharge side of compressor stations)
- Type of coating (asphalt, tape, etc.)
- Condition of coating (disbonded, degraded)

- Found more frequently at the bottom of the pipe
- History of cathodic protection levels on the pipeline

Near Neutral pH SCC

- Pipe information (grade, diameter, year of manufacture, type of weld, and other relevant construction information)
- Operational information (MAOP, etc.)
- Soil formation and topography
- Temperature (higher temperatures increase the risk of SCC)
- Stresses on the pipeline (found mostly near suction and discharge areas of pump stations, and near discharge areas of compressor stations)
- Type of coating (asphalt, tape, etc.)
- Always found under shielded disbonded asphalt or tape coating

All of this data must be studied, a model developed to identify: areas where SCC is expected to occur, areas where SCC is not expected, and areas where SCC activity cannot be determined. The pipeline should then be excavated and inspected with the findings used to refine the model. Ultimately, the goal is to locate all critical areas, repair them, and identify areas that must be monitored to ensure pipeline integrity.

8.7.3.4 Remediation of SCC

If SCC is found, repair priority should be based on the depth of the cracks, the coalescence of the crack colonies, and the calculated length of interactions. The following are several methods used to repair SCC cracks:

- Replace the section of the pipe;
- Remove the cracks by grinding; because cracks are stress risers, removing the cracks eliminates the stress risers. Refer to company manual for maximum grinding depth; if complete removal of a crack requires grinding that exceeds maximum allowable grinding depth, the pipe must be replaced or reinforcement sleeves installed.

- Type A sleeve (reinforcement sleeve)
- Type B sleeve (pressure containing sleeve)
- Steel compression reinforcement sleeve
- Composite reinforcing sleeve (such as Clockspring)

Additional measures can be taken to reduce the probability of crack initiation and growth. Such measures include lowered temperature (for high pH SCC), reduced pressure fluctuations, and cathodic protection. Cathodic protection levels more negative than the potential range would be required, and an -850 mV IR drop free or more negative would be very beneficial. One method to reduce or control the threat of SCC is to ensure the pipe potential is maintained at a level more negative than -850 millivolts. Cathodic protection systems with long line anodes are being used with great success to boost the pipeline potential to control SCC cracking. Additional cathodic protection in conjunction with recoating is a good method to control stress corrosion cracking.

In summary, perhaps the greatest integrity challenge related to stress corrosion cracking is to determine whether stress corrosion cracking is happening before failures occur. The second challenge is to mitigate stress corrosion cracking once it is discovered and institute measures to control or halt crack growth.

8.8 Summary

Technical challenges that, for the foreseeable future, will be faced by pipeline operators include:

- Materials with inadequate properties and defects
- Pipe with manufacturing defects
- Defects and damage introduced during construction
- Damage caused by operating and service conditions
- Damage caused by outside forces

There are, of course, other difficulties the pipeline industry faces that were not addressed in this chapter; they include:

- Obtaining, integrating, filtering and managing the huge volume of information related to pipeline integrity to readily indicate integrity issues and deficiencies on individual pipelines
- Finding adequately trained and experienced personnel to fulfill requirements of successful pipeline integrity management
- Improving existing technology and/or developing new technologies to improve (or enable) identification of pipeline integrity deficiencies

Guidance and information about the numerous challenges are available from a variety of sources; they include regulatory agencies, industry organizations, pipeline operators, service companies, industry training organizations, and universities. Some of the better-known sources are listed below:

- American Gas Association – www.aga.org
- American Petroleum Institute – www.api.org
- American Society of Mechanical Engineers – www.asme.org
- Association of Oil Pipe Lines – www.aopl.org
- Gas Technology Institute – www.gastechnology.org
- NACE International – www.nace.org
- Pipeline Research Council International – www.prci.com
- Society for Protective Coatings – www.SSPC.org
- Southern Gas Association – www.southerngas.org
- U.S. D.O.T. Pipeline and Hazardous Materials Safety Administration - www.phmsa.dot.gov

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Chapter 9: Remediation Activity/ Repair Methods

After completing this chapter, students should be able to:

- Recognize when to conclude that pipeline integrity threats exist.
- Assess all the parameters needed to develop a repair plan.
- Determine if a pressure reduction is appropriate.
- Identify the available remediation methods and associated criteria.
- Recognize the appropriate repair protocol for high consequence areas (HCAs).

9.1 Discovery of Anomalies

Pipeline repair and remediation are required when anomalies or defects are discovered that could compromise the integrity of the pipeline. Discovery is considered to have occurred when operators have adequate data to verify that threats exist. Discovery must occur within 180 days of an integrity assessment unless it can be demonstrated that doing so is impractical.

9.1.1 Definitions

An **anomaly** is an irregularity detected by NDE but which has yet to fail an appropriate assessment code or method.

A **defect** is a discontinuity or imperfection of sufficient magnitude to warrant rejection on the basis of an Integrity Standard, assessment code, or method.

Fitness For Purpose means the system or component is fit to operate until the next service period (shut down).

Fitness For Purpose Assessment is a multidisciplinary engineering analysis of equipment to determine whether it is fit for service, typically until the next service period (shut down).

Discovery is considered to have occurred when any of the following occurs:

- When pipeline operators receive preliminary inline inspection reports that prove integrity threats exist.
- When pipeline operators receive final in-line inspection reports that prove that integrity threats exist. (Final inline inspection reports must be received by pipeline operators within 180 days of the inspection tool runs.)
- When integrity assessment information from any source is adequate to prove that integrity threats exist.
- When integrity assessment information from numerous sources have been gathered and integrated, and the integrated information proves that integrity threats exist. (The date of discovery can be no later than the dates of completion of integration of integrity assessment information.)

9.1.2 Defects that Compromise Pipeline Integrity

During the normal operation of a pipeline anomalies and defects may be discovered that will compromise the integrity of the pipeline and require repairs to restore the pipeline to its original design specifications. The decision to make repairs could result from:

- Hazardous gas or liquid release
- Leak detected by a third party
- Leak detected during a leak detection survey
- Anomaly detected as part of a pipeline integrity assessment
- A defect discovered during excavation of the pipeline

When an anomaly or defect is discovered, the operator should consider safety and environmental issues. The next step is to determine if the repair can be made while the pipeline remains in service. The steps required to undertake an in-service repair differ significantly from those of a pipeline taken out of service. The operator should understand the precise impact of the following issues:

- the necessity for and degree of pressure reduction before excavation
- personnel and public safety during excavation
- gathering critical information on the pipeline
- characterizing the anomalies and locating them by direct inspection and testing during excavation

9.2 Defect Characterizations

Remediation depends on the history of the pipeline and environment. Before any repairs the characteristics of the anomaly or defect must first be detailed in order to determine the extent of pipeline damage. Accurate information is essential to choosing the appropriate repair procedure; if questions about the accuracy of the information come up, the operator's technical experts should be consulted. Once the site of the anomaly is excavated, a "fitness for service" evaluation must be made. At this point if the anomaly characteristics match one or more of the categories listed below it can then be termed a defect. Documentation is required to verify if the defect poses a threat to pipeline integrity. A repair plan must be formulated for those that fail the fitness test. The root cause of the anomaly should be determined to preclude re-occurrence or increase in severity.

Typical defect characterizations include:

- Corrosion
  - general corrosion
  - pitting/localized corrosion
  - crevice corrosion
  - stress corrosion cracking
- Gouges and grooves
- Dents
- Arc-burns
- Inclusions
- Laminations

- Weld defects

General pipeline facility repair requirements in 49 CFR 192.703 (for natural gas pipelines) and 49 CFR 195.401 (for hazardous liquid pipelines) require repair of conditions that are “unsafe" or “could adversely affect the safe operation of [the] pipeline system.”

The following guidelines should help in characterizing the defects listed above. Appropriate company experts should help ensure that all activities are in line with both company specific requirements and industry standards.

9.2.1 Corrosion

When a defect’s only characteristic is a measurable reduction in wall thickness it is termed corrosion or general metal loss. Evaluation is applicable to external corrosion and general metal loss defects in pipe walls, girth welds, or longitudinal seams. Follow the appropriate methods detailed in ASME B31G, Simplified RSTRENG, LAPA RSTRENG, or other documents, and in accordance with company specifications. If a pipeline has corrosion damage in the longitudinal seam, replacement of the affected segment is required if it includes pre-1970 Electric Resistance Welded (ERW) or flash welded pipe, regardless of the severity of the corrosion.

- **General Corrosion**

  If the corroded area is small, the pipe should be replaced, repaired, or operated at a reduced pressure if the wall thickness is less than the design thickness calculated in accordance with ASME B31.4, paragraph 404.1.2. For general corrosion, the remaining life can be calculated with reasonable certainty using available reliable general corrosion rates.

- **Localized Corrosion**

  The pipe should be replaced, repaired, or operated at a reduced pressure if localized pitting has reduced the wall thickness to less than the design thickness calculated in accordance with ASME B31.4, paragraph 404.1.2. Other restrictions apply in accordance with ASME B31.4, paragraph 451.6.2. In particular, this method does not apply to electric resistance welded (ERW) or electric-flash welded seams.

- **Stress Corrosion Cracking**

  If there is a concern about possible cracking, magnetic particle or similar techniques should be used to inspect for cracking. All cracks must be removed; repair is not a viable option for SCC. This is principally because the remaining life cannot be determined with reasonable certainty since there are no reliable crack growth rates.

In general, all pipes containing leaks should be removed or repaired based on the allowable pipeline repair options detailed in ASME B31.4, paragraph 451.6.2, Section (b). If the pipeline can be taken out of service, it should be repaired by cutting out a cylindrical piece of pipe containing the anomaly and replacing it with a pipe that meets the requirements of ASME B31.4, paragraph 401.2.2 and having a length of not less than one-half diameter.

9.2.2 Gouges and Grooves

Gouges are often elongated grooves and could exist internally or externally on a pipe as shown in Figure 9.1. They are usually caused by mechanical removal of metal. Sharp grooves can act as stress concentrators which can lead to various kinds of cracking.

Evaluating metal loss from scratches, gouges, grooves, mill pits, grinding marks, and other defects should be done to determine the extent of damage. If the extent is limited to a general reduction in wall thickness, the defect could be characterized similar to "corrosion or general metal loss." However, if sharp edges or other characteristics that could impair pipeline integrity are present, the defects can not be characterized as "corrosion or general metal loss." These characterizations may include:

- Sharp defect edges
- Stress concentrators such as scratches, gouges, grooves, or mill pits
- Hard spots
- Cracking
- Plastically deformed material

Gouges and grooves having a depth greater than 12.5% of the nominal wall thickness require repair or removal and replacement in accordance with ASME B31.4, paragraph 451.6.2, Section (b).

Figure 9.1 Shallow Aligned Gouges on the Internal Surface of a Pipe

9.2.3 Dents

A depression that produces a disturbance in the curvature of the pipe wall without reducing the pipe wall thickness can be characterized as a dent. The depth of a dent should be measured from the lowest point of the depression to a straight line representing the original contour of the pipe. It is advisable to also inspect the dent for possible cracking. Many companys' criteria for evaluating the survivability impact of the dent include consideration of the orientation and contour of the dent.

Generally, dents meeting any of the following conditions shall be removed or repaired:

- All dents which affect the curvature of the pipe at the seam or at any girth weld
- All dents containing a stress concentrator, such as a scratch, gouge or groove

- All dents exceeding ¼ inch (6mm) in pipe NPS 4 or smaller
- A dent exceeding 6% of the nominal diameter in sizes greater than NPS 4
- All dents containing external corrosion where the remaining wall thickness is less than 87.5% of that permitted by the material design specification

9.2.4 Arc Burns

Electrical arcs produce localized melting and rapid subsequent cooling of materials, thereby causing a local degradation of material properties which may lead to cracking and pipeline failure. An arc burn is a burn sustained by a material from an electric arc either by the extreme heat it produces or through radiation. An arc burn may be evidenced on metallic surfaces by a small circular or semi-circular heat-affected area on the surface which may contain shallow pitting, re-melting or cracking.

Arc burns can cause serious stress concentration in a pipeline. They should be prevented, removed, or repaired. The notch caused by arc burns can be removed by grinding, provided the resulting wall thickness is not less than that permitted by the material design specification. If the wall thickness is less, then the portion of the pipe with the arc burn must be removed or repaired per ASME B31.4, paragraph 451.6. Areas where grinding has reduced the remaining wall thickness to less than the design thickness calculated in accordance with ASME B31.4, paragraph 404.1.2, or decreased by an amount equal to the manufacturing tolerance applicable, must be removed or repaired.

9.2.5 Inclusions

Inclusions could be classified as pre-service material production flaws which are often discovered during in-service inspection. Slag inclusions are various non-metallic substances that become entrapped in the weld during the welding process. Typically, weld inclusions are located near the surface and along the side of the weld. (See Figure 9.3). The key decision that needs to be made is whether the inclusions are likely to progress in the future based on the material, stress, service conditions, and size. If the inclusions are judged to be a threat to the safe operation of the pipeline, the pipe section should be removed or repaired.

9.2.6 Laminations

A lamination is a separation within the metal wall caused by the presence of highly elongated non-metallic inclusion (e.g. oxides, sulfides, or silicates). Laminations are generally aligned parallel to the surface of a pipe, plate, or tube. Figure 9.2 shows cracking in weld deposit caused by lamination in steel base metal.

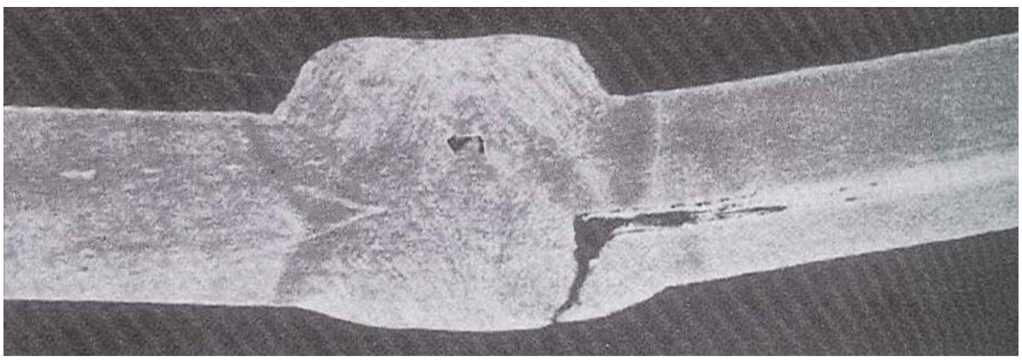

Figure 9.2 Cracking in a Weld Deposit Caused by Lamination in Steel Base Metal

Laminations or notches on pipe ends do not need repair, rather the damaged end should be removed as a cylinder and the pipe end properly rebeveled. Generally, laminations, split ends, and/or other pipe defects should be repaired or removed in accordance with the allowable pipeline repair methods described in ASME B31.4, paragraph 451.6.2(b).

9.2.7 Weld Defects

All welds found to have defects as set forth in ASME B31.4, paragraph 434.8.5(b) or in the appropriate pipe specification must be removed or repaired. Generally the authorization for weld repair, removal, or repair of weld defects must be in accordance with API 1104. Examples of various weld defects appear in Figure 9.3.

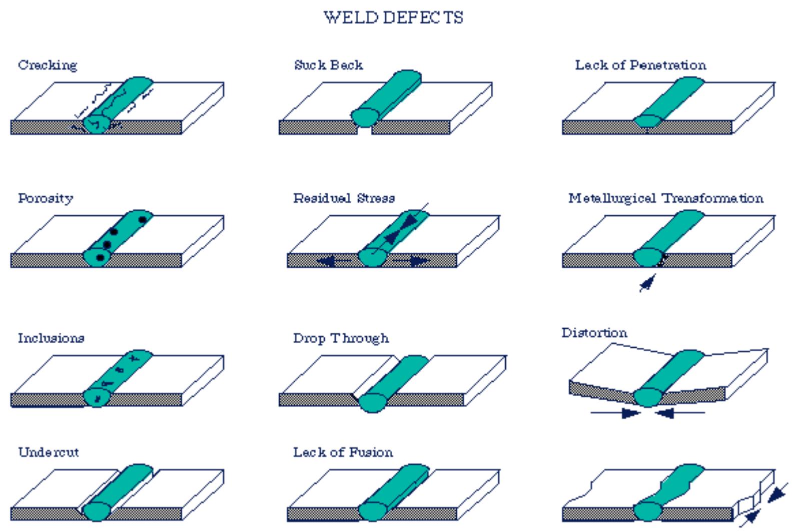

Figure 9.3 Various Types of Weld Defects

9.3 Development of Repair Plan

Before an appropriate repair can be successfully and safely made, information needs to be gathered about parameters or factors to ensure a sound repair decision. These parameters generally fit into the following categories:

- Pipe material
- Pipeline product and operating characteristics
- Pipeline construction
- Type and characteristics of the anomaly

It is also useful to have information about the availability of repair materials and personnel. The personnel need to be qualified and should be know the inherent risks in performing the repair. Specific knowledge of leak history, past defects, and past repairs need to be considered also.

9.3.1 Pipe Material

It is necessary to know the nominal diameter and wall thickness, the material grade, and type of longitudinal seam for the pipe segment needing repair. In some cases it may be critical to know the pipe manufacturer, date of manufacture, coating type, chemical composition, and properties relating to fatigue and fracture toughness.

9.3.2 Pipeline Product and Operating Characteristics

Operational characteristics must be known and understood. These include the maximum allowable operating pressure (MAOP) or the maximum operating pressure (MOP) of the pipeline. In addition, the discrete point pressure at the location of the repair may also be required. Other things to consider are:

- pressure fluctuations
- operating temperatures
- the type of product in pipeline
- flow velocity

It should be determined if the repair is permanent or temporary. Temporary repairs may be convenient at the time but the operator should evaluate how and when the repair will be made permanent. The effect of the repair on future inspections and testing of the pipeline need to be considered.

9.3.3 Pipeline Construction

The operator needs to know the construction history and physical location of the repair, as well as the bends and ease of operation for the construction equipment. The location and type of girth welds or pipeline connections and appurtenances must be known if mechanical couplings or oxy-acetylene girth welds are contemplated. Attention must be paid to any special precautions necessary prior to excavation.

9.3.4 Type and Characteristics of the Anomaly

Finally, the characteristics of the anomaly need to be considered. Both the repair plan and the choice of repair techniques are directly related to the type of defect being repaired. Key issues include:

- evaluation of the necessity and the degree of pressure reduction before excavation
- consideration of personnel and public safety during excavation
- collection of critical information on the pipeline
- characterization of the anomalies and location by direct inspection and testing

9.4 Repair Protocol for "High Consequence Areas" (HCA) Pipeline

The integrity management standards for hazardous liquid pipelines, 49 CFR 195.452 and Natural Gas Pipelines 49 CFR 192 Subpart O, specify the time periods for pipeline repairs. For hazardous liquid pipelines, the regulations require an operator to respond to conditions discovered. Regulation 49 CFR 195.492 requires that defects meeting certain criteria must be responded to immediately or within 60 to 180 days, depending on the defect severity. This regulation further requires an operator to use alternative mitigation measures, such as lowering the MOP, if they cannot make the repair within the specified period for any reason, including difficulty in obtaining required permits.

Any anomalies, defects, or conditions that threaten the integrity of hazardous liquids pipelines in "high consequence" areas (HCAs) must be remedied within specific periods of time following discovery to comply with U.S. D.O.T. "High Consequence Areas" integrity management regulations for hazardous liquids, 49 CFR 195.452.

This is the only regulation that specifies time periods for pipeline repairs. This regulation requires an operator to remediate defects meeting certain criteria immediately or within 60 or 180 days, depending on the defect's severity. This regulation further requires an operator to use alternative mitigation measures if they cannot make the repair within the specified period for any reason, including difficulty in obtaining required permits.

Specifically, 49 CFR 195.452 (h) (3) specifies, in part:

- An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure.
- Thus, if an operator must obtain a permit to carry out a repair for the operator's integrity management program and cannot obtain the permit and make the repair within the 60- or 180-day period, an operator may reduce operating pressure as an interim mitigative measure. If the operator determines that pressure reduction is impracticable, it must submit a notification to RSPA/OPS explaining how it will ensure safety in the interim period, and then continue operation until the permit is granted and the repair made. An operator must complete the repairs in a time frame that does not jeopardize safety or environmental protection. Again, if the specified time period cannot be met because the operator is waiting for a permit to be granted, RSPA/OPS expects an operator to show it has applied for the permit and is taking all necessary steps for the permit to be processed and granted.

Remediation time periods are normally based on the severity of the integrity threats and are divided into the following categories: (1) immediate remediation, (2) 60-day remediation, (3) 180-day remediation, and (4) 365-day remediation.

9.4.1 Immediate Remediation

The HCA regulation does not define the term “immediate.” Pipeline operators have been informed informally by D.O.T. personnel that “immediate” means as soon as reasonably and practicably possible. Pipeline operators react based on the severity of the indicated anomaly, defect, or other condition. The criteria for immediate remediation are:

- Metal loss greater than 80% of nominal pipe wall thickness

- Predicted burst pressures less than maximum operating pressures (MOP)
- Dents on top of pipe (8 to 4 o'clock) with any indications of metal loss, cracking or stress risers
- Dents on top of pipe (8 to 4 o'clock) with depths greater than 6% of nominal pipe diameter
- Any other indicated anomalies or defects judged to require immediate repair

Operating pressure must be reduced immediately when anomalies or defects are discovered that require immediate repair, and must remain reduced until repair is completed.

9.4.2 60-Day Remediation

The criteria for 60-day remediation are:

- Dents on top of pipe (8 to 4 o'clock) with depths greater than 3% of nominal pipe diameter for pipes with a nominal diameter of 12 inches or larger, or with depths greater than 0.25 inches for pipes with a nominal diameter less than 12 inches
- Dents on bottom of pipe (4 to 8 o'clock) with any indications of metal loss, cracking or stress risers

9.4.3 180-Day Remediation

The criteria for 180-day remediation are:

- Dents that affect pipe curvature at girth welds or longitudinal seams where dent depths are greater than 2% of nominal pipe diameter for pipes with a nominal diameter of 12 inches or larger, or where dent depths are greater than 0.25 inches for pipe with a nominal diameter less than 12 inches
- Dents on top of pipe (8 to 4 o'clock) with depths greater than 2% of nominal pipe diameter for pipes with a nominal diameter of 12 inches or larger, or with depths greater than 0.25 inches for pipes with a nominal diameter less than 12 inches
- Dents on bottom of pipe (4 to 8 o'clock) with depths greater than 6% of nominal pipe diameter

- Corrosion damage with predicted safe operating pressure (SOP) less than maximum operating pressure (MOP)
- General corrosion damage with metal loss depths greater than 50% of nominal pipe wall thickness
- Metal loss with depths greater than 50% of nominal pipe wall thickness at crossings of other pipelines
- Metal loss with depths greater than 50% of nominal pipe wall thickness in areas with widespread circumferential corrosion
- Metal loss with depths greater than 50% of nominal pipe wall thickness that could affect circumferential welds
- Crack indications determined to be cracks upon excavation and examination
- Metal loss in or along longitudinal seams
- Gouges or grooves with depths greater than 12.5% of nominal pipe wall thickness

9.4.4 Other Remediation Within Appropriate Time Periods Determined by Pipeline Operators

The criteria for other conditions requiring remediation are:

- Significant, detrimental change since last assessment
- Mechanical damage on top of pipe (8 to 4 o'clock clockwise)
- Anomalies abrupt in nature
- Anomalies oriented longitudinally on pipe
- Anomalies of large areas
- Anomalies inside or near casings
- Anomalies at crossings of other pipelines
- Anomalies in areas with suspect cathodic protection

9.4.5 365-Day Remediation

This relates to anomalies, defects, or other conditions resolved by reducing maximum operating pressure (MOP); this is considered a temporary remedial action. Appropriate permanent remedial actions must be taken within 365 days of discovery.

9.4.6 Other Remediation That Does Not Meet Immediate, 60-Day, 180-Day or 365-Day Repair Criteria

Indicated anomalies, defects, or other conditions that do not pose short-term integrity threats and do not meet immediate, 60-day, 180-day or 365-day repair criteria must be re-assessed on or before the end of the next assessment period, and the repair criteria applied at the time of the re-assessment.

9.5 Types of Remediation Activities/ Repair Methods

The type of repair chosen is based on several considerations. Guidance is provided in a number of documents including: the PRCI Pipeline Repair Manual, ASME B31.8S-2004 "Managing System Integrity of Gas pipelines," ASME B31G-1991 "Manual for Determining the Remaining Strength of Corroded Pipelines – A Supplement to ASME B31 Code for Pressure Piping," ASME B31.4-2002 "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids," API RP579-2000 "Fitness for Service (FFS)," and API 1104-1999 "Welding of Pipelines and Related Facilities" among others. The following descriptions detail common repairs and their applicability for various kinds of repair.

9.5.1 Replacement of a Pipe Section

When a section of pipe must be removed and replaced, the replacement should have similar (if not the same) characteristics and have a design-strength equal or greater than the section it replaces. It is best if the line can be taken out of service to effect the repair. Pipe replacement ensures that the pipeline is restored to its original design specifications. Replacement should be considered when a severe anomaly or defect is detected or if steel or composite sleeves are not feasible due to pipe configuration. Replacing a complete section of pipe minimizes the number of circumferential welds in the pipeline. Some replacement concerns are:

- Preparation for and shut down of product and pipeline according to company's standard operating procedures
- Verification of design criteria
- Welder qualification

If the section of replacement pipe was not pre-tested, the pipeline must be hydrostatically tested. The tie-ins need to be recoated and given cathodic protection before the line can be brought back into service.

Pipe replacement is a good repair method for all anomalies or defects, however it is the most expensive. When feasible, operators usually consider using other in-service repair methods.

9.5.2 Pressure Reduction

Operating pressure reduction may be required because a condition is discovered that impairs pipeline integrity. Operating pressure reduction is usually not considered for permanent repairs, but is rather a short-term remedy to provide the operator with a margin of safety until a permanent repair is made. Situations that may require pressure reduction are:

- Metal loss defects found by in-line inspection
- Defects discovered during excavation
- Leaking defect, unknown defect or other factors
- When in-service repairs are being made to the pipeline

If an operator is required to obtain a permit to make a repair but cannot obtain the permit and make the repair within the 60 or 180 day period, a reduction of operating pressure can be an interim mitigation measure. If the operators determine that pressure reduction is impracticable, they must submit a notification to RSPS/ OPS to detail how they will ensure safety in the interim period. They are then allowed to continue operation until the permit is granted and the repair made.

An operator must complete the repairs in a time period that does not jeopardize safety or environmental protection. Again, if the specified time period cannot be met because the operator is waiting for a permit to be granted, RSPS/OPS expects an operator to show it has applied for the permit and is taking all necessary steps for the permit to be processed and granted.

Pressure reduction is usually a temporary measure made until remediation is completed. Pressure reductions can be 80% of the ***recent*** operating pressure at the location, or the safe pressure calculated from the dimensions of the anomaly (refer to B31G, LAPA etc). "***Recent***" in this context is typically considered to be not more than one year for a gas pipeline and no more than 60 days for a liquid pipeline.

Most operators also grant their field personnel permission to lower the pressure further if their judgment/experience indicates the need. For example, it might be warranted if field personnel discover an interacting defect, or environmental or stress levels not anticipated in the normal pressure reduction plan. Factors which may influence the decision to reduce the pipeline pressure are:

- Operating and construction history of the pipeline
  - Type of girth weld/coupling
  - Type of seam weld
  - Age of pipe
  - Expected manufacturing, construction, or operation defects
- History of stress corrosion cracking
- Type of work to be done
  - Lowering/raising
  - Inducing pipeline stresses
- Anomaly/defect characteristics
  - Known
  - Unknown
- Percentage of SMYS at which the pipeline operates
- Class location
- Poor site conditions

Any one or combination of these adverse factors can warrant an even more severe pressure reduction. Operators can also give their field personnel permission to make a complete line pressure reduction if it is deemed necessary in order to maintain safety.

9.5.3 Recoating Resulting From Engineering Critical Assessment (ECA)

Once an external anomaly or defect is excavated, it must be evaluated, an ECA performed to prove that the anomaly or defect does not pose a threat to the integrity of the pipeline. That is, no repairs are required. Determining the root cause of the anomaly should be done to preclude a re-occurrence or an increase in severity. Following the ECA, the pipeline may be recoated and backfilled.

It is acceptable to repair the topcoat if the other coats are in good condition and do not exhibit any signs of corrosion, flaking, or disbondment. The top and intermediate coats may be repaired if the primer exhibits no sign of corrosion. Good practice dictates that the area to be repaired should be prepared by one or more of the following methods:

•Using sandpaper or low pressure abrasive brush-off (sweep) blast to promote adhesion to the surrounding coating

•High pressure water cleaning (HPWC) up to a maximum of 10,000 psi to remove loose rust, dirt, loose old coatings, and soluble salts

•Low pressure water jetting (LPWJ) up to a maximum of 20,000 psi to remove tight rust, caked mud, tight old coatings and soluble salts.

Before removing an existing coating, a sample should be tested for lead unless it has been previously determined to be lead-free. If lead is found, it must be removed, contained, and disposed of according to the governing regulation. The existing coating system must first be identified before being repaired to ensure that the new coating system is compatible. An example of incompatible coatings is top coating an existing inorganic zinc coating with an alkyd. The chemical reaction that takes place will saponify the alkyd, leaving a thin, soap like film between the steel and the coating, which destroys the adhesion and leads to coating disbondment.

New coatings on the market may not be compatible with existing coatings due to changes in formulations to meet health and environment requirements. It may be necessary to apply a test patch of the new coating over the existing coating to determine if they are compatible. If the existing coating becomes soft or there is a loss of adhesion within seven days, it is not compatible and should not be used. A situation like this may require that the existing coating be removed in order to re-coat. If the existing coating system cannot be identified, a sample along with the appropriate paint form should be sent to an approved lab for testing. Factors to consider in determining the type of repair coating to be used are:

- Compatibility of the repair coating to the existing coating
- Surface preparation
- Operating conditions of the pipeline
- Application method
- Environmental conditions

9.5.4 Grind Repair

Shallow cracks or gouges can be repaired by hand filing or grinding with a power disk grinder. Grinding is considered a permanent repair if it eliminates the stress concentrating effect of the defect, removes damaged material, and the amount of metal removed has not diminished the pressure capacity of the pipeline. Prior to beginning grinding repairs, the actual thickness of the pipeline wall must be determined by ultrasonic testing and the absence of internal corrosion or laminations verified. Ultrasonic testing should also be performed periodically during the grinding procedure to monitor the amount of metal that is removed. The allowable amount of metal removed should be verified according to industry standards and the operator's internal standard operating procedures.

After completing the repair, the affected area should be tested using magnetic particle inspection or liquid penetrant inspection to verify that the repair was successful. B31G or RSTRENG can be used to assess/determine if the remaining wall thickness is sufficient.

Some operators do not permit grinding as a method of pipe repair.

9.5.5 Welding

Repairing a pipeline by replacing lost or damaged metal by depositing weld metal is a low cost alternative repair method. This repair method may be used when full encirclement sleeves or composite sleeves are not feasible, such as the repair of fitting and field bends. The method is generally not recommended for pipes with external metal loss greater than 80%.

Prior to welding, the repair area should be cleaned to bright metal and all corrosion should be removed. The remaining wall thickness should be tested using ultrasonic testing. The repair should be inspected and recoated prior to restoring the pipeline to service.

9.5.6 Full Encirclement Sleeves (Types A and B)

Full encirclement steel pipe sleeves are widely used to repair certain defects and restore pipeline service. There are many configurations of full encirclement sleeves available for permanent pipeline repairs and are classified as either Type A sleeves or Type B sleeves. Type A sleeves are used to reinforce pipe only; they are not used to repair leaks or circumferential defects. The Type B sleeve is used for pressure containment.

9.5.6.1 Type A Sleeve (Reinforcing)

The Type A full encirclement steel sleeve is only acceptable for use on non-leaking defects; it reinforces the pipe at the defect and prevents bulging. Type A sleeves consist of two halves of a steel pipe cylinder or two curved steel plates that are placed around the pipeline at the defect. The sleeve should be long enough to extend at least two inches beyond the defect area. The two halves are joined together by welding the side seams. During installation a reduction of operating pressure is recommended to ensure that the defect does not start leaking during installation. The ends of the sleeve are not welded to the carrier pipe; they are sealed to prevent water from entering the annular space and creating a potential for corrosion. The main advantage of the Type A sleeve is that there is no welding performed on the carrier pipe. The disadvantages are that the sleeve cannot be used on a leak or circumferential defect. There is the potential for corrosion in the annular space between the carrier pipe and sleeve.

9.5.6.2 Type B Sleeve (Pressure Containing)

The Type B sleeve is very similar to the Type A. However, since the Type B sleeve is a pressure containing sleeve it should be designed to the same specifications as the carrier pipe; the ends of the sleeve are welded to the carrier pipe. The Type B sleeve can be used on leaking pipes or defects with a wall loss greater that 80%. This type of sleeve can be detected by an in-line inspection and be used for circumferential defects. The disadvantages are that since the ends of the sleeve are welded to the carrier pipe, ultrasonic inspection is required.

9.5.6.3 Composite Sleeve

Composite sleeves can be used to cover metal wall loss from corrosion, repair mechanical damage, or repair plain dents. There are several types of composite sleeve systems, for example, Wet Lay-Up and Lay-Up. Wet Lay-Up system examples include Armor Plate Pipe Wrap, the Black Diamond, and Aquawrap. These are monolithic; they can be applied to non-straight geometries and are versatile in their range of epoxy products. Lay-Up system examples include Clockspring and Permawrap. Lay-Up was the first widely-used composite repair system. They are limited to repairing straight pipes because they are a layered repair system.

As part of the procedure, each of the manufacturers must have had an engineering evaluation made on their product's performance. This evaluation should be presented to the user. The user must receive training from the vendor on the proper application techniques and any other considerations. Environmental concerns, among others, may be an issue.

The following factors should be including in choosing a composite repair method:

- Strength of composite material
- Environmental effects
- Effects of pressure
- Mechanics of load transfer from pipe to wrap

- Long-term performance issues
- Consistency of application
- Quality control in manufacturing
- Applicability guidelines

The epoxy filled sleeve is a composite version of the Type A sleeve. The two halves of a shell are placed around the pipe and bolted into place. The ends are sealed with filler material. After the filler has hardened, epoxy is pumped into the annular space between the carrier pipe and sleeve until the space is full.

9.5.7 Mechanical Leak Clamp

Mechanical clamps are typically used to repair leak defects caused by external corrosion and are not considered permanent repairs. The installation of a full encirclement mechanically split sleeve is normally carried out in accordance with ASME B 31.4 paragraph 451.6.2(c).

Chapter 10: Inspection and Assessment Intervals

After completing this chapter, students should be able to:

- Understand how growth rate applies when determining inspection and assessment intervals.
- Determine the remaining life of a pipeline in the post assessment phase of an ECDA project in a case study or scenario.
- Determine when confirmatory direct assessment is necessary after an initial direct assessment has been completed.

Inspection and assessment intervals for a prescriptive integrity management plan are normally consistent with the recommendations depicted in Table 6.7, "Prescriptive Integrity Assessment Intervals (ASME B31.8S-2004) Time Dependent Threats, Prescriptive Integrity Management Plan," on page 33 of Chapter 6. In general, to establish appropriate intervals between inspections, operators should consider many factors, such as remaining life, defect types and sizes detectable by the inspection method used, stress levels, defect growth rates, and the effectiveness of actions taken to correct chronic time-dependent problems.

10.1 Assessment Intervals

Operators must consider many factors in establishing appropriate assessment intervals between inspections such as:

- defect types and sizes detectable by the inspection method used
- stress levels
- defect growth rates
- effectiveness of actions taken to correct chronic time-dependent problems.

If corrosion defects are found after an inspection, remaining life calculations are needed to determine re-inspection intervals. Remaining life of a pipeline is the time it will take for the most severe remaining corrosion anomaly to grow to leakage or failure.

According to US Pipeline Safety regulations for natural gas pipelines, an operator must conduct periodic evaluations as frequently as needed to assure the integrity of each covered segment.

Normally, the reassessment interval should not exceed one-half of the shortest remaining life calculated. Otherwise, the reassessment interval shall be consistent with the recommendations depicted in Table 6.7 of Chapter 6.

10.2 Remaining Life

The remaining life of a pipeline in an ECDA region is considered the time it will take for the most severe remaining corrosion anomaly within the ECDA region to grow to leakage or failure. The remaining life is normally considered and calculated during the Post Assessment step of the External Corrosion Direct Assessment (ECDA) process. According to NACE SP0502 (latest version), no remaining life calculation is needed if no corrosion defects are found. If this is the case, the remaining life can be considered the same as for a new pipeline. If corrosion defects are found, remaining life calculations are needed to determine reinspection intervals. The Post Assessment step also requires defining the reassessment intervals, assessment of ECDA effectiveness, and feedback.

Common methods used to determine remaining strength are RSTRENG, ASME B31G, Modified B31G, and DNV Standard RP-F101. Each operator must decide which method is best for their system. Whichever method is used to determine remaining strength should be well documented. Depending on the results of the calculations, it could be necessary to repair or replace the pipe at corroded areas. If the calculated safe pressure is less than the operating pressure at a location, it may still be necessary to reduce the pressure until a repair is made.

10.2.1 Strength/worst Remaining Flaws

According to NACE SP0502 Section 6.2.2, the maximum remaining flaw size at scheduled inspections should be considered the same as the most severe in all locations excavated. In addition, if the root cause analyses indicate that the most severe flaw is unique, the size of the next most severe flaw may be used for the remaining life calculations.

If remaining life calculations are needed, calculation of the growth rate of the corrosion should be based on sound engineering practices. If a corrosion growth rate is not available, the values and methods used in NACE SP0502 Appendix D can be used. If the remaining life is based on corrosion that is continuous and of typical size and geometry, the Time until Failure (TF) equation, considered to be quite conservative for external corrosion on pipelines, may be used.

In actual practice, however, the Remaining Life (RL) of a pipeline is taken to be the lesser of the calculated Time until Failure (TF) and Time until Leakage (TL):

$$TF = C \times SM\ (t/GR)$$

$$TL = (t-d)/GR$$

The constants are defined in Table 10.1:

Table 10.1: Definition of Terms

Term	Definition
C	Calibration Factor (dimensionless)
RL	Remaining Life (years)
TF	Time until Failure (years)
TL	Time until Leakage (years)
SMYS	Specified Minimum Yield Strength (psig)
YP	Yield Pressure (psig)
MAOP	Maximum Allowable Operating Pressure (psig)
FP	Fail Pressure (psig)
MPR	MAOP Ratio = MAOP/ yield pressure (dimensionless)
FPR	Failure Pressure Ratio = FP/ yield pressure (dimensionless)
SM= FPR – MPR	Safety Margin (dimensionless)
t	Nominal wall thickness (inches [mm])
OD	Outside Diameter (inches)
d	Corrosion depth (inches)
GR	Corrosion Growth Rate (inches per year)

The following are good examples of problems relating to remaining life.

Example 1

ECDA direct examinations on an X52 carbon steel gas pipeline 30” (762 mm) x 0.375” (9.5 mm) with an MAOP of 936 psig revealed a worst case corrosion area 1” (25.4mm) long with a maximum depth of.29 inches (.73 mm). What is the remaining life of the ECDA region?

1. In accordance with Section 6.2.2 of NACE SP0502, the maximum remaining flaw size is assumed to be the same as the most severe flaw excavated, namely: 1 inch (25.4mm) long x 0.290 inches (.73 mm) deep.
2. Using the modified ASME B31G equation, the calculated failure pressure (FP) of the pitted area is 1474 PSIG.
3. Calculate Yield Pressure (YP) using the Barlow formula:

$$YP = \frac{2 \text{ x SMYS x t}}{OD} = \frac{2x52000x0.375}{30} = 1300psig \qquad [10.1]$$

4. Calculate Failure Pressure Ratio (FPR), MAOP Ratio (MPR) and Safety Margin (SM):

$$FPR = \frac{FP}{YP} = \frac{1474}{1300} = 1.134 \qquad [10.2]$$

$$MPR = \frac{MAOP}{YP} = \frac{936}{1300} = 0.720 \qquad [10.3]$$

$$SM = FPR - MPR = 1.134 - 0.720 = 0.414 \qquad [10.4]$$

5. The corrosion growth rate (GR) is assumed to be the default value of 16 mpy = 0.016 inches (.40 mm)/year. The time until failure is calculated as follows:

$$TF = C \times SM \frac{t}{GR} \qquad [10.5]$$

$$TF = 0.85 \times 0.414 \times \frac{0.375}{.0160} = 8.2 \text{ Years} \qquad [10.6]$$

The time until leakage (TL) for a 290 mil pit in 0.375 inches (9.5 mm) wall pipe at the same corrosion rate (16 mpy) is calculated as follows:

$$TL = \frac{0.375 - 0.290}{.0160} = 5.3 \text{ Years} \qquad [10.7]$$

6. The remaining life of the pipeline in the ECDA region is taken as the lesser of the calculated values in steps 4 and 5 above. In this example, remaining life would be the time until leakage occurs (5.3 years).

10.3 Growth Rate

The growth rate used for remaining life should be based on the actual corrosion rate data applicable if available. In cases where actual rates are not available, the corrosion growth rate may be assumed to be the default value of 16 mpy = 0.016 inches (0.40 mm)/year for the ECDA region. If, however, it can be shown that cathodic protection for the applicable segment has met the 40 mV polarization criteria for most of its life, the default value of the corrosion growth rate may be reduced to 12.2 mpy. If the soil resistivity and drainage characteristics are known, a still lower default corrosion growth rate value may be used. This fact is illustrated in Table 10.2.

10.3.1 Internal Corrosion

Corrosion monitoring is generally recognized as the best tool for long-term detection and trending of internal corrosion in oil and gas operations. Cost-effective monitoring systems include:

- A series of weight-loss corrosion coupons (fitted for easy access) to obtain pitting and general corrosion rates for long-term corrosion trending
- Electronic probes for short-term corrosion trending, i.e., Linear Polarization Resistance (LPR) Probes and Electrical Resistance (ER) probes
- Biostuds and/or coupons to monitor for sessile bacteria
- Grid arrays of ultrasonic transducers attached to the outside of pipelines

Internal corrosion rates can be calculated in mils per year (mpy) by considering pipe-relevant factors for gas and liquid transportation in accordance with Section 7 of NACE Standard TM0169 (latest version), “Laboratory Corrosion Testing of Metals” or Section 2 of NACE Standard RP0775, “Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations.” Pitting corrosion rates can be calculated in mils per year (mpy) as in Section 2 of NACE Standard RP0775 or ASTM G 46, “Standard Guide for Examination and Evaluation of Pitting Corrosion.”

Corrosion rates (CR) are normally calculated from the measured weight loss as shown below:

CR in mils per year = [(weight loss in grams) (22,300)/(area in square inch) (metal density in grams/cm3)].

The degree of pitting can be assessed from the calculation of pitting rate as shown below:

Pitting rate in mils per year = [(maximum pit depth in mils) (365)/ days of exposure]

When using coupons please note that results are inconsistent if the coupon surface is coated with paraffin or oil. Short-term exposure will also produce misleading results. Radiography and ultrasonic methods are also used to determine remaining wall thickness.

10.3.2 External Corrosion

External corrosion growth rate is the rate at which corrosion grows on the external surface of a pipeline. According to GRI04/0093.6, a conservative approach to estimating external corrosion is the default corrosion rate value of 0.4 mm/y (16 mpy). This figure is taken from Appendix D of NACE SP0502. NACE SP0502 also goes on to say that the value can be reduced by up to 24% if documented evidence shows that CP for the segment being evaluated has had at least 40 mV of polarization (considering IR drop) for most of the time since installation. Table 10.2 depicts Uhlig's Corrosion Rates for Steel in Soil (in mpy). This chart can be used as a guide to determining corrosion rates and remaining life for pipelines given soil resistivity and drainage in the environment.

Table 10.2: Uhlig's Corrosion Rates for Steel in Soil
(Uhlig's Corrosion Handbook, Second Edition, Copyright 2000)

Environmental Factors	General Corrosion Rates*			Pitting Corrosion Rates*		
	Maximum	Minimum	Average	Maximum	Minimum	Average
Soil Resistivity						
Less Than 1,000	2.5	0.7	1.3	12.2	4.3	7.9
1,000 to 5,000	2.3	0.2	0.7	17.7	2.0	5.5
5,000 to 12,000	1.3	0.2	0.7	9.1	2.4	5.5
Greater Than 12,000	1.4	0.1	0.6	10.2	1.2	4.3
Drainage						
Very Poor	2.3	1.5	1.8	17.7	6.3	11.0
Poor	1.5	0.4	0.9	9.1	2.0	5.5
Fair	2.5	0.7	0.9	12.2	3.1	6.3
Good	0.9	0.1	0.4	7.1	1.2	4.3

*Expressed in Mils Per Year (that is, 1/1000-inch per year)

Example 2

ECDA direct examinations on an X52 carbon steel gas pipeline 30" (762 mm) x 0.375" (9.5 mm) with an MAOP of 936 psig revealed a worst case corrosion area 6" (152.4 mm) long with a maximum depth of .150 inches (3.8 mm). What is the remaining life of the ECDA region?

In accordance with Section 6.2.2 of NACE Standard SP0502, the maximum remaining flaw size is assumed to be the same as the most severe indication excavated: 6 inches (152.4 mm) long x 0.150 inches (3.8 mm) deep.

Using ASME B31G, the calculated failure pressure (FP) of the pitted area is 1222 PSIG.

1. Calculate Yield Pressure (YP) using the Barlow formula:

$$YP = \frac{2 \times SMYS \times t}{OD} = \frac{2 \times 52000 \times 0.375}{30} = 1300 \text{ PSIG} \qquad [10.8]$$

2. Calculate Failure Pressure Ratio (FPR), MAOP Ratio (MPR) and Safety Margin (SM):

$$FPR = \frac{FP}{YP} = \frac{1222}{1300} = 0.940 \quad [10.9]$$

$$MPR = \frac{MAOP}{YP} = \frac{936}{1300} = 0.720 \quad [10.10]$$

$$SM = FPR - \text{MPR} = 0.940 - 0.720 = 0.220 \quad [10.11]$$

3. The corrosion growth rate (GR) is assumed to be the default value of 16 mpy = 0.016 inches (.40 mm)/year. The time until failure is calculated as follows:

$$TF = C \times SM \frac{t}{GR} \quad [10.12]$$

$$TF = 0.85 \times 0.220 \times \frac{0.375}{.0160} = 4.4\text{Years} \quad [10.13]$$

4. The time until leakage (TL) for a .150 inch (3.8 mm) pit in 0.375” (9.5 mm) wall pipe at the same corrosion rate (16 mpy) is calculated as follows:

$$TL = \frac{t-d}{GR} = \frac{0.375 - 0.150}{.0160} = 14.1\text{Years} \quad [10.14]$$

5. The remaining life of the pipeline in the ECDA region is taken as the lesser of the calculated values in steps 3 and 4 above. In this example, remaining life would be the time until failure occurs (4.4 years).

In the example given above, the conservative default value of 16 mpy was used for the corrosion growth rate. If it can be shown that CP for the segment has met the 40 mV polarization criteria for most of its life, the default value can be reduced to 12.2 mpy. Recalculating TF and TL would give values of 5.7 and 18.4 years respectively.

If the soil resistivity and drainage characteristics are known, a lower value could be selected from Table 10.2. If the soil resistivity and drainage characteristics are known, a lower value could be selected from Table 10.2. For example, if the ECDA region was in soil with a resistivity greater than 12,000 ohm-cm in an area with poor drainage, a value for GR of 10.2 mpy taken from the “maximum” column could be used. Recalculating TF and TL would give values of 6.8 and 22.0 years respectively.

10.3.3 Stress Corrosion Cracking (SCC)

Stress corrosion cracking is the failure of normally ductile metals which have been subjected to constant tensile stress in a corrosive environment, particularly at elevated temperatures. Corrosion cracks propagate over a range of velocities and could be as high as 10 mm/h, depending upon the alloy combination and the environment. Although SCC initially grows slowly, it may reach a critical transition size from the relatively slow crack growth rates associated with stress corrosion to the fast crack propagation rates associated with purely mechanical failure. SCC is initiated by the presence three factors:

- a susceptible material
- an environment that fosters SCC in that material
- sufficient tensile stress to induce SCC

According to NACE SP0204 Stress Corrosion Cracking (SCC) Direct Assessment Methodology:

- It is up to the discretion of the operator to establish the number of additional investigations that are required on a given segment and the reassessment intervals based on information such as:
    - The extent and severity of the SCC detected during the original investigation.
    - The estimated rate of propagation of the crack clusters and remaining life of the pipe containing the clusters.
    - The total length of the pipe segment.
    - The total length of potentially susceptible pipe within the segment.
    - The potential consequences of a failure within a given segment.
- The company shall consider whether the criteria used for dig site selection in the initial assessment are appropriate for the reassessment.

10.3.4 Distribution of Corrosion Anomalies

As detailed in Chapter 2, the various forms of corrosion that constitute the controlling mechanisms for internal corrosion, external corrosion, and/or stress corrosion cracking include:

- uniform or general corrosion
- localized corrosion
- galvanic corrosion
- microbiologically influenced corrosion (MIC)
- environmentally assisted cracking (EAC)
- intergranular corrosion (IGC)
- de-alloying cleavage
- velocity-related corrosion

In pipeline operation, these mechanisms do not usually occur in isolation. For example, production wells are prone to general and pitting corrosion. In flowlines, living microbial communities create biofilms capable of capturing and accumulating all sorts of solids from the fluid system. All deposits create conditions conducive to localized corrosion or deposit attack by their presence in the pipe. This can happen inside a pipeline with low velocity, high water cut, and fine suspended sand particles that trap water around the 6 o'clock region of the pipeline. The distribution of corrosion anomalies could include general corrosion, localized pitting corrosion, and MIC, as well as cracking. Each of the anomalies resulting from these mechanisms could form corrosion clusters.

A corrosion cluster is defined as two or more adjacent corrosion features in the wall of a pipe or in a weld that may interact to weaken the pipeline more than either would individually. The interaction rules for cluster recognition and identification are normally set by the operating company. A cluster is assigned a length equivalent to the overall length of the clustered features and a depth based on the deepest feature within the cluster.

Locations with the highest potential for corrosion accumulation for the longest duration have the highest likelihood of producing significant corrosion clusters. Corrosion accumulation for extended time periods makes it possible for a variety of corrosion mechanisms to take place simultaneously and/or consecutively. This is true for internal and external corrosion, for gas, oil, or multiphase systems alike. Locations conducive to corrosion which can generate multiple anomalies include:

- pig launchers/receivers
- drips at a pipeline, metering station, compressor station, etc.
- dead ends, dead legs or any isolated section of a pipe or facility without flow
- vessel or header drain lines
- tanks
- liquid recovery vessels such as slug catchers, separators, scrubbers, etc.
- metering tubes
- side streams and sample loops
- low areas such as sags, river crossings, etc.

The internal corrosion cluster threat in liquid petroleum pipelines is based on the supposition that corrosion will only occur when water and solids "drop" out of the hydrocarbon phase and accumulate on the steel surface of the pipe. Internal or external heat-affected zones on pipelines that happen to be in the vicinity of sites with the highest potential for corrosion accumulation will be more highly susceptible.

Because of the high probability of cluster corrosion in such locations, inspection and assessment intervals should be skewed to ensure that those locations are assessed more frequently. Indeed, in the case of wet gas transmission lines, operators often pig the pipeline to control corrosion by removing liquids/solids that accumulate in the low spots of the pipeline. Such periodic and frequent removal of accumulated biofilms, deposits, and liquids from gas pipelines reduces the probability of clustered corrosion.

In a pipeline section susceptible to corrosion, corrosion anomalies are bound to be concentrated and a variety of tools are needed to assess them. Even then, it is not realistic to expect the tool reports to perfectly predict corrosion anomalies based on the cluster interaction rules specified by the operator (see Figure 10.1). A probability distribution approach would be better to rank ILI corrosion anomalies. Regardless of which approach is used to rank risk anomalies, the end result will most likely dictate a more frequent re-assessment interval. Fundamental factors to establish appropriate inspection intervals include:

- Remaining life
- Distribution of corrosion anomaly types and sizes
- Stress levels
- Corrosion anomaly growth rates
- Effectiveness of actions taken to correct chronic corrosion anomalies.

Figure 10.1 Internal Corrosion Cluster in Crude Oil Production Line
(with High CO_2)

Pipeline integrity protocol also demands that the anomaly risks are ranked to prioritize corrosion remediation, excavations, and to develop re-inspection intervals. However the accuracy of ILI tools is questionable when used to characterize the variety of corrosion anomaly types enumerated above. There is a significant gap between the inspection capability of existing ILI tools and the inspection needs of the pipeline industry. The inspection tool may report several features in close proximity that do not meet the cluster interaction rules specified by the operator. The length and width of features measured in the field may not correlate exactly to the dimension reported by the ILI tool.

These difficulties are further compounded by the fact that corrosion is usually characterized as significant based upon the maximum depth of corrosion (e.g., greater than 50% wall loss) or the ratio between the predicted failure pressure and the maximum allowable operating pressure. The maximum depth in this regard does not normally refer to pitting depth, which may turn out to be far more critical in determining the time until leakage (TL) and thus, the remaining life (RL) of the pipeline segment. For example, the massive leak of BP pipelines at Prudhoe Bay was caused by clustered pitting corrosion anomalies likely due to MIC and underdeposit corrosion. Located around the 6 o'clock position of the pipeline and spaced about 5-10 feet (1.52-3.04 meters) apart, they apparently went undetected.

10.3.5 Methods to Determine Growth Rate

Corrosion growth rate can be determined in a number of ways including those mentioned above; it can also be estimated using a Magnetic Flux Leakage (MFL) tool. An MFL tool can show the current static state of a pipeline that could grow as a function of time. MFL tools can be used to collect periodic corrosion data to calculate growth rates. These tools normally collect data approximately every 2 mm along the axis of the pipe. Multiple periodic inspections and accurate corrosion growth analysis are required to obtain a more complete understanding of the corrosion activity. Standard resolution MFL tools normally report corrosion defects as: (1) light, corresponding to 10% to 30% of wall thickness, (2) moderate, 30% to 50%, or (3) severe, greater than 50%. High resolution MFL is far more accurate and its data can be used to calculate the remaining strength of a pipe. Some companies also use data correlation and software modules to determine corrosion growth rates.

Ultrasonic testing is normally used to measure thickness losses, due to internal corrosion, in order to make structural integrity pressure calculations. For direct examination purposes, grid arrays of ultrasonic transducers, having two rows of ten transducers each, are arranged next to each other and attached horizontally to the outside of a pipeline at the 6 o'clock position. The number of the 2 x 10 grids used depends on the extent of the suspected thickness loss. Indeed, it is possible to use only one 2 x 10 grid and move it systematically to inspect the entire exposed location.

The data from each transducer in the grid(s) is statistically analyzed to monitor the average general corrosion rate and increases in the aerial extent of corrosion as a function of time. The transducers in this case would have a broader beam to inspect a wider area, but the resolution of each transducer would be about +/-2 mil (where a mil is 0.001 inch). Compared to the use of coupons or internal probes, this resolution is poor. On the other hand, single high resolution UT transducers do have resolutions as low as 0.1 mil, which is quite comparable with probe monitoring. Comparing measurements at 90-180 day intervals provides an estimation of corrosion trends and rates.

Radiography testing is also used for thickness measurements at specific intervals. In operation, the X-ray source is located at the 12 o'clock position and the film at the 6 o'clock position, both on the exterior surface. It measures wall thickness changes after the damage has already occurred. Similar to ultrasonic testing, comparative measurements taken at 90-180 day intervals provide an estimate of corrosion trends and rates.

10.4 Confirmatory Direct Assessment

According to US Pipeline Safety regulations for natural gas pipelines, an operator must conduct periodic evaluations as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on the electronic code of federal regulations (e-CFR), Title 49, Part 192. For example, Section §192.917 emphasizes periodic data integration and risk assessment for the entire pipeline. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933), as well as additional preventive and mitigation actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

The pipe can be assessed using pressure tests, inline inspection tools, direct assessment, other methods, or confirmatory direct assessment (under conditions specified in §192.931).

Confirmatory Direct Assessment (CDA) can be used on a covered segment that is scheduled for reassessment at a period longer than seven (7) years. If confirmatory direct assessment is used, it must incorporate §192.937 and have a plan that meets the requirements of §192.925 (ECDA) and §192.927 (ICDA). CDA can only be used on a covered segment to identify damage resulting from external corrosion or internal corrosion.

10.5 External Corrosion Confirmatory Direct Assessment (EC-CDA)

An operator's CDA plan to identify external corrosion must comply with §192.925 with the following exceptions:

- The indirect examination may use only one indirect examination tool (suitable for the application)
- The procedures for direct examination and remediation must permit
  a. All immediate action indications must be excavated for each ECDA region
  b. At least one high risk indication that meets the criteria for action must be excavated in each ECDA region

If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502, Section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.

10.6 Internal Corrosion Confirmatory Direct Assessment (IC-CDA)

An operator's CDA plan to identify internal corrosion must comply with §192.927 except that the plan's procedures identify locations for excavation may require more than one excavation at high risk locations in each ICDA region. In the detailed examination process, locations with an inclination greater than the critical angle should be examined moving downstream from beginning of a region. If no angles greater than the critical angle exist, the location with the highest inclination should be examined.

If corrosion is found, one additional location should be selected for validation purposes. To be sure that the locations most likely to have internal corrosion are the actual locations being examined, at least two inspections must be made in the sub-region between the beginning of the ICDA region and the first site examined. If the detailed examination process identifies the existence of extensive and severe internal corrosion, the operator should return to pre-assessment because the applicability of Dry Gas-ICDA may be in question. The ICDA process optimizes the search for corrosion-susceptible sites and is able to target locations of likely corrosion more accurately.

Chapter 11: Post Integrity Assessment Risk Analysis

After completing this chapter, students should:

- Be familiar with changes that could trigger risk re-assessments.
- Be familiar with specific integrity data that should be integrated into risk assessment plans.

Risk analysis, risk quantification and its use in pipeline/segments ranking was the focus of Chapter 6. In it qualitative risk assessment approaches, risk-based inspection (semi-quantitative) approaches, quantitative risk assessment approaches, and risk software tools for use in pipeline segment ranking was discussed.

The concepts discussed in this chapter naturally dovetail with Chapter 6. To fully grasp this, it is essential to review the key elements of an integrity management program (IMP) as illustrated in Figure 7.1.

The results from an integrity assessment could trigger the need for an immediate risk reassessment, possibly right after remediation activities aimed at:

- Reducing the magnitude of consequence
- Reducing the probability of failure
- Enhancing the survivability of the facility and people
- Mitigating the primary source of consequence

11.1 Risk Re-assessment in Response to Management of Change Processes

Generally, it is necessary to conduct post-integrity-assessment risk analysis when the management of change process indicates.

How are these changes dictated and how do they come about?

Systemic changes and implementation of new maintenance practices would trigger the need for a risk re-assessment. A formal change management program would address the technical, physical, procedural, and organizational changes to the system that should trigger risk reassessments. Operators should be able to recognize situations requiring changes to the integrity management program and plans. Precisely documented records of all changes including new technology applications should be available and all changes must be communicated to the parties affected. An on-going review process should assess the safety impact of any potential change and all changes should be evaluated prior to implementation.

Changes in Process Conditions

Some deterioration mechanisms are affected by process changes. If such a mechanism were identified by the integrity assessment, then a post-integrity-assessment risk analysis might be called for. Typical deterioration mechanisms that are dependent on process conditions are stress corrosion cracking, wet hydrogen sulfide cracking, and sour water corrosion.

Changes in Consequences

If, after an integrity assessment, a pipeline segment is reclassified, then a post-integrity-assessment risk analysis might be required.

Other Changes

Other significant changes that might necessitate a post-integrity-assessment risk analysis include: (a) repairs/replacements involving changes in materials, (b) change in product values, (c) revision in safety and environmental laws regulations, and (d) changes in risk criteria.

Time-dependent Monitored or Scheduled Defects

For monitored or scheduled indications, a post-integrity-assessment risk analysis might be performed during the intervening period.

After Prevention Activities

Preventive actions may include changes of material, system re-design, and/or operation personnel training. Such actions, once completed, might require post-integrity-assessment risk analysis.

11.2 Risk Re-assessment in Response to Changes Due to Remediation

A remediation action is a corrective action taken to mitigate corrosion as well as the deficiencies in the corrosion protection system identified by the integrity assessment. This could include relocation, replacement, rehabilitation, repair, monitoring, and/or chemical treatments. A post-integrity-assessment risk analysis is needed not only to calculate the residual risk, but also to answer the question of whether or not the resulting residual risk is as low as reasonably practicable.

11.2.1 Integrating Integrity Conclusions into Risk Assessment Plans

Data integration should make all pertinent integrity information available for risk assessment plans. For successful data integration, you must chose the basis for correlating the integrity information. An example of a good basis for data integration is location information in four dimensional space and time (x, y, z, and time). The resultant integrated information should be formatted to allow ready identification of all the pertinent integrity/risk issues. In the final analysis, flexibility is the key. The process of integrating integrity conclusions should be flexible enough to accommodate changes in pipeline systems, in public and environmental exposures, evolving operating and maintenance procedures, emerging technology, and evolving regulations.

Using the direct examination phase of the three direct assessments methods (ICDA, ECDA, SCCDA) as an example, data from the three methods could be integrated by spatially aligning all identified anomalies/indications to determine possible anomaly overlaps, correspondence, and/or nearness. The cost-effectiveness of this approach is the fact that a single excavation could satisfy the inspection requirements for two or three DA processes. That is, integrating DA integrity conclusions could “kill three birds with one stone” and contribute more greatly to the overall risk assessment plans.

Generally, the established processes of data collection, review, analysis, integration, etc., should be in place from the conception of the integrity management program. This process should start with a sound design, a sound material-selection strategy, and a sound construction philosophy. The process of planning, assessing, and evaluating iteratively provides better data to perform the next risk assessment since risk assessment is a continuous process.

According to API 1160-2001:

"The pipeline operator learns more about the risks of the pipeline system with each risk assessment. Using this knowledge, the operator must periodically review and alter, as needed, a schedule for re-assessment of each pipeline system or segment."

11.3 The Need for Electronic Database for Data Integration

The large amount of inspection and monitoring data as well as probability and consequence data collected over the lifetime of a pipeline should be integrated and stored in a database. This includes information pertaining to the ASME B31.8S list of 21 threats. In particular, it includes the results from the following integrity assessment methods: in-line inspection, hydrostatic testing, ICDA, ECDA, and SCCDA. According to ASME B31.8S Section 4.5.

"*For integrity management program applications, one of the first data integration steps includes development of a common reference system (and consistent measurement units) that will allow data elements from various sources to be combined and accurately associated with common pipeline location.*"

"*Individual data elements shall be brought together and analyzed in their context to realize the full value of integrity management and risk assessment. A major strength of an effective integrity management program lies in its ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence that a specific threat may or may not apply to a pipeline segment. It can also lead to an improved analysis of overall risk.*"

Data integration requires observations and integrity assessment results from past years and current inspections to yield viable and reliable data sets as a basis to make good decisions. This integration is labor-intensive and difficult in that inspection techniques for various data sets are usually different, data quality terms are often missing, important references are not documented, recorded information lacks sufficient details, and data may reside within different department databases. Therefore, a considerable amount of time and effort is required to collect, collate, and arrange existing and new data, from internal or external sources, in a format that makes comparison and integration possible. Data should never be integrated into any database, application, or integrity management plan without first being validated.

It is essential to have a data management system (an electronic database) that is capable of storing and integrating a substantial amount of data from many types of sources. The electronic database should be to integrate a large amount of in-line and non-inline inspection data for the IMP. Changing and updating reference points, and cross-referencing data from different tools should be made easy to do. Combination, permutation and correlation of information between ILI, hydrotesting and direct assessments should be easy to perform and such data should be available for sorting, filtering and searching using “key words.” The data system should make it possible to prioritize anomalies based on such combined information.

Integrity data, stored in a GIS (Geographic Information System) database format, should be incorporated into the GPS (Global Position Surveying) system. GIS facilitates a graphic view of a pipeline system changing easily from high-level overviews to specific details. GPS allows simultaneous field capture of pipeline data and mapping with significant accuracy. Thus, the data management system should be compatible with integrated GIS/GPS systems to transfer, retrieve, and compare previously logged ILI data for corrosion trending, tabular data, actual photos, and engineering assessments.

The database should be able to import documents, photographs, videos, drawings, etc. and allow displays of aerial pictures with superimposed maps and pipeline drawings for selected defects.

This assures real-time data quality and seamless integration of integrity conclusions into subsequent risk assessment plans. The data management system should also incorporate post-integrity-assessment information from defect assessment modules, MOP calculations, remaining life calculations, etc.

11.4 Specific Data That Should Be Integrated Into Risk Assessment Plans

Well integrated integrity data helps pipeline operators maintain the flow and cross-referencing of IMP data. Analyzing such data makes comparison of coincidental occurrence of suspected high-risk conditions, indications or events possible. Data integration and periodic risk re-assessment make it possible for operators to identify integrity issues that might otherwise go unnoticed.

According to API 1160-2001:

"The strength of a risk assessment is in its ability to compare the existing data for the coincident occurrence of suspected high-risk conditions or events. The user will be collecting data that indicates risk-increasing conditions, as well as activities that will confirm or deny the impact of suspected risk conditions. Integration of data is an integral part of this approach."

Whether or not to integrate integrity conclusions into risk assessment plans depends on whether or not such conclusions might affect any part of or the entire pipeline integrity program. Specific data that should be integrated into risk assessment plans include any data related to risk-increasing indicators as well as any information about the corresponding activities that confirms or denies the presence or absence of the risk-increasing indicators under consideration. A versatile data management system with good in-built procedures makes comparison of coincident occurrences of suspected high-risk conditions (with corresponding confirmation activities) much easier and more accurate. Key integrity conclusions that should be integrated and considered for risk re-assessment include:

- The number of repairs required following integrity assessments and mitigation activities including additions, deletion, or modification to the pipeline;
- The types and the causes of defects identified by the integrity assessments;
- The potential consequences of the indications identified by the integrity assessments;

- The history of all defects and failures;
- The rates of degradation of the pipeline/segment;
- The quantity and quality of information known about the pipeline;
- The pipeline sections exhibiting characteristics in common with newly discovered pipeline defects;
- Any change in service or significant change in operating parameters, or fluid transported that would affect risk prioritization and spill control;
- All repair decisions, preventative, and mitigating activities;
- The known positions in four dimensional space and time (x, y, z, and time) of each indication/anomaly;
- Any change in performance of corrosion control and protection;
- Any changes in corrosion rates;
- The complete historical knowledge (particularly the corrosion trend analysis);
- Any pipeline segment severity re-classification and category re-prioritization;
- All remaining strength evaluation, root cause analysis, and remediation activities;
- The data collected during direct examination; and
- The data from periodic assessments.

Table 11.1 illustrates an example of how data integration could provide an answer to an integrity issue. The risk-increasing indicators to the left, when integrated with the information to the right about the corresponding activities that confirm or deny the presence of the risk-increasing indicators, would provide an answer to the following question:

"*What is the likelihood of third-party damage (TPD) at a location on the pipeline?*"

Table 11.1: An Integration Example: Potential for TPD
(Source: API 1160)

Integration Example: Potential for TPD	
Risk-increasing Indicators	**Confirmation Activities (Confirm or Deny)**
Patrol Frequency Depth of Cover Construction or Farm Activity Third-party Leak History One-call Activity	In-line Inspection (ILI) Dent Survey Third-party Leak History Pipe Exposure Reports
Question: What is the Likelihood of TPD at a Specific Location Along the Pipeline?	

The key is to document ALL data and information about data (metadata) that might affect any or the entire pipeline integrity program in a database. The combination, permutation and correlation of the data, within the data management system, can then be integrated into the risk assessment plans. The issues that could affect any part of or the entire pipeline integrity program are reflected in the following questions:

- Could the integrity conclusions alter the impact zones?
- Do the integrity conclusions influence any assumptions made during previous risk assessments?
- Would the integrity conclusions affect subsequent inspection, prevention, or mitigation plans?
- Would the integrity conclusions result in the revision of the integrity management plan?
- Would the integrity conclusions influence the integrity program for pipeline stations, terminals, and/or delivery facilities?
- Would the integrity conclusions affect any performance indication or auditing criteria?

If the answer to any of these questions is positive, then such integrity conclusions should be integrated into risk assessment plans.

Chapter 12: Integrity Management Plan

After completion of this chapter, students should:

- Understand the basic structure of an Integrity Management Plan.
- Understand the reasoning and rationale for comprehensive documentation requirements for an Integrity Management Plan.
- Realize the inviolable importance of requiring proper approval and the communication of these concepts and procedures company wide.
- Possess a clear understanding of the regulatory requirements to properly maintain systems for control and maintenance for an Integrity Management Plan.

12.1 Integrity Management Plan

The integrity management plan is developed by identifying all pipeline threats; integrating pipeline data from all sources; assessing risk; evaluating system integrity; and defining measures for mitigation. This is an iterative process applied until all threats are evaluated and processes are in place to address integrity threats. Qualified process planners should be the first to begin developing processes to deal with integrity threats that might be of critical danger to the populace, the environment, pipeline assets, or involve significant financial liability to the pipeline operator. By establishing processes and control of these threats means they can be maintained in a logical, planned state of control.

There are two general types of integrity management plans: (1) prescriptive-based, and (2) performance-based. A performance-based plan requires far more detailed data and analysis of the pipeline and its condition. The more comprehensive and detailed the methodology, the greater the flexibility in scheduling and choosing mitigation methods. In a prescriptive plan, less detail is required but the interval for reassessment may be shorter depending on regulatory prescriptions.

12.1.1 Prescriptive Plan

A prescriptive-based risk assessment process follows preset conditions that result in fixed inspection, detection, mitigation, and timelines. It requires the operator to follow these fixed steps to produce the necessary results. The prescriptive process relies on qualitative probability and consequence analyses to prioritize risk. Subject matter experts (SMEs) constitute the backbone of prescriptive-based risk assessment. SMEs are from the operating company and/or consultants who have expertise in specific areas of operation and have the necessary technical information to provide descriptive data using sound engineering judgment and experience. The relevant regulatory bodies prescribe the prevention, detection, mitigation, and timelines for periodic risk and integrity assessments. The name derives from the fact that the process depends on regulatory prescriptions. Figure 1.2, Figure 1.3 and Figure 1.4 in Chapter 1 depict prescriptive integrity management plans for the three major corrosion failure types.

A performance-based risk assessment process does not follow preset conditions. It allows the operator more freedom and greater flexibility to meet or exceed the required results. It utilizes risk management principles and assessment to determine prevention, detection, mitigation, and timing. The complexity level of the method used to assign specific failure probability and consequence values depends on whether an initial or a repeat integrity assessment is planned. For an initial assessment, any of the prescriptive-based methods could be utilized. Repeat assessments are based on more complex methodologies to assign specific probability and consequence values. Such complex methods could be quantitative, semi-quantitative, or combinations of both. A semi-quantitative methodology combines both quantitative and qualitative methods.

12.1.2 Performance Plan

A performance plan evaluates the effectiveness of a pipeline integrity program in meeting company-specific goals and objectives. It focuses on identification of integrity risks, how identified threats were handled, and advances to assure future overall integrity of the pipeline system. The plan requires that the evaluation be done quarterly or annually; it also mandates that metrics be established to calculate the effectiveness of each aspect of the integrity program. Selected metrics to evaluate the effectiveness of the integrity management program are shown in Figure 6.2 of Chapter 6. Performance measures such as these are applied on a periodic basis to evaluate both prescriptive and performance-based integrity management programs, local and threat-specific conditions, and overall performance. Provisions are also made to revise, as more information becomes available, the integrity management plan, the communications plan, the management of change plan and the quality control plan. The philosophy focuses on continuous improvement.

Whether a prescriptive or performance based integrity mechanism is adopted, the key is to develop processes which will prevent critical dangers to humans, the environment, pipeline assets, and significant financial liability to the pipeline operator. The integrity management plan documents each step including strategies to prevent specific integrity threats, detect existing threats, and mitigate the risk. The risk assessment methodology chosen can use any approach that can be technically supported. It should include a schedule through which the pipeline segments at highest risk are addressed first. It should also provide for continuous improvement by incorporating new information as well as using new technology.

12.1.3 Management of Change

As outlined in 49 CFR 192/195, ASME B31.8S and NACE Standard SP0502, Management of Change (MOC) procedures must be developed in order to identify, evaluate and consider the impact of all changes to the pipeline, pipeline systems, and facilities and the integrity of all. All procedures must be comprehensive, yet flexible enough to accommodate all changes whether major or minor. Similarly, they should be written and conveyed in a manner that is technically sound, but also remain easily understood by all personnel who use them.

Any sound MOC system must address technical, physical, procedural, and organizational changes to the basic system whether the change is temporary or permanent. The MOC system should, at a minimum, mandate planning and procedures for these conditions as well as evaluate any unique consequences which may exist.

The pipeline operator must realize that changes, whether they are physical or procedural, typically require revisions to the company's Integrity Management Program (IMP). Similarly, revisions to the IMP can require changes which must be reflected in MOC and Quality Assurance-Quality Control (QA-QC) documentation.

As outlined in ASME B31.8S any MOC process should include, but not be limited to the following:

- Reason and Rationale for change
- Physical Change (pipeline and associated facilities)
- Procedural, Operational or Organizational Change
- Established line of authority for submittal and approval of changes
- Analysis of implications for change
- Acquisition of required work permits and processes – external and internal
- Comprehensive documentation – both physical and procedural
- Communication of change to affected parties and update of master documents impacted by such changes
- Time limitations or other factors which could delay or otherwise impact required changes – Immediate vs. Routine
- Qualifications of staff members

Even complex changes can be outlined in such a way that they are easily understood. Regardless of the complexity of any change to the physical pipeline operation or associated administrative controls, MOC and QA-QC documentation is fundamental. Flow charting is a common and logical method used to show the processes involved in making changes. Figure 12.1 represents a typical flow chart showing the processes of changes.

It is imperative that a logical plan for change be documented and followed; both submission and evaluation of suggestions must follow an established and proven process prior to final approval and implementation.

It is important to grasp that any change, regardless of its complexity, could impact the integrity and, therefore, potential risk to the pipeline, personnel, public/private property, and the general public as a whole. MOC documentation must be technically sound, logical, and presented in language and format to ensure everyone can understand them. They should also establish order and control during times any physical/procedural changes to the pipeline or MOC-QA-QC processes changes are planned or undertaken. All systems should be designed carefully enough to provide levels of safety high enough to ensure trust by all company personnel and the general public. The operating companies should also ensure that personnel and the general public are aware that changes are inevitable and that well documented contingency plans and procedures are in place to minimize any potential risk, regardless of its impact.

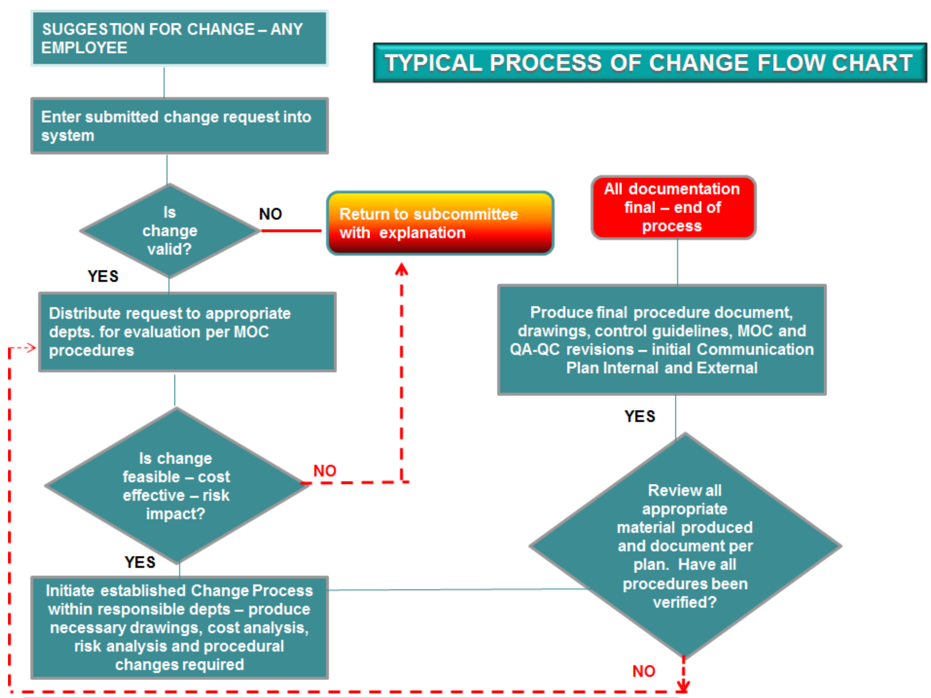

Figure 12.1 Typical Flow Chart Used to Convey the Processes of Change

A management of change plan establishes the formal procedure to identify changes and their impact on pipeline integrity plans. A pipeline system and its environment are constantly changing, and whether the changes are permanent or temporary, they need to be fully documented for future risk assessment and pipeline integrity evaluation. Risk assessment and threat identification are "updated" or "changed" through two processes: (1) data integration and (2) continuous activities. Risk assessment provides an updated segment risk score that the data integration team reviews to determine if a change to the risk assessment interval and/or baseline assessment plan is warranted. Threat identification identifies actionable threats that need be evaluated by the preventive and mitigative measures process. Continual iterative evaluation including management of change, initiates the changes that need to be made to the integrity management plan.

12.1.3.1 Communication Plan

The Communication Plan addresses the dissemination of information to employees, the public, and local, state and federal authorities having jurisdiction. It should include regular, scheduled communications about integrity initiatives and program results. The company web site is an effective communications tool. In addition, procedures for company response to specific requests should be built in. Landowners in the vicinity of the pipeline should be given contact information in case of emergencies. Emergency responders should be familiar with emergency reporting and damage prevention procedures.

Company wide communication of all changes absolutely must be an integral part of any MOC or quality control system. Communication should be in writing, not only within the company, but to external sources deemed appropriate by the pipeline operator, or as outlined in federal regulations and ASME standards. Examples of potential external dissemination of change information must include, but not be limited to the following:

Landowners and the general public

- Company/operator names, locations and contact persons
- General location of pipeline and its facilities
- Pipeline product
- How to identify and report a suspected or active leak
- General information regarding the operator's emergency preparedness and response information

- Damage prevention – one-call numbers, excavation notification, contact numbers in case of damage

Local Emergency Response and Public Officials

- Regular distribution of maps and company contacts to all municipalities in areas subject to possible risk
- Summary documentation of IMP and emergency preparedness procedures maintained by the operating company

Local and Regional Emergency Response

- Maintain liaison with all potential emergency response personnel
- Local fire and police departments
- City and county emergency management departments
- Company names, contacts for both routine and emergency response
- Local maps, preferably indicating pipeline right-of-way, pipeline facilities, etc.
- Pipeline product
- Facility locations and descriptions
- How to identify, report and respond to a suspected or active leak
- General information regarding pipeline operator's IMP, preventative/integrity programs and emergency preparedness plans
- Station locations and descriptions
- Emergency capabilities – internal and external
- Coordinate operator's emergency preparedness with local officials

As soon as a suggested change is submitted, the first people contacted should be the appropriate qualified personnel, particularly those involved in evaluation and approval. Operations management must not only understand its critical importance, but be willing to maintain their IMP diligently. To do this, there has to be a logically structured procedure to effectively disseminate planned change data throughout the company. Internal communication processes have to be effective in both routine and emergency situations, and must be an integral part of the MOC and QA-QC systems.

When the change is a newly updated system, operator qualification reviews should be required. When new technology is introduced supervisory and operations personnel should be required to train and re-qualify for the design and operation of new systems. In each case, training and certification documentation should be required to meet staff qualification requirements as outlined in the company's QA-QC, MOC and IMP programs.

12.1.4 Quality Assurance (QA) and Quality Control (QC)

As defined in ASME B31.8S-2004, Quality Control is the "documented proof that the operator meets all the requirements of their Integrity Management Program." The QA-QC Plan generally addresses documentation, implementation and maintenance of company processes and procedures. Typically, a minimum of six activities are required to do this:

- Identify processes to be included in the QA-QC and MOC program.
- Logically determine and define the sequence and interaction of these processes.
- Determine criteria and methods required to confirm that both operation and control of these process are effective.
- Outline the resources and information required to support operation and monitoring of these processes and procedures.
- Monitor, measure, and analyze the processes. A statistically sound evaluation is the ultimate tool to control procedures and processes.
- Take action to achieve desired results and continue improvement of the processes and procedures.

A well conceived, properly balanced QA-QC plan will document the steps to maintain the quality of the MOC and the IMP and ensure continuing improvement. Quality control procedures need to make it easy to accurately verify and maintain documentation as well as audit plan components as needed.

The IMP and MOC must work together with the over-arching QA-QC plan and its mandatory audits to endure compliance with all regulatory requirements.

A QA-QC system is typically all encompassing. It should manage and control the flow of all operations throughout the company including management, personnel, processes, procedures, materials, procurement, purchasing, document control, engineering, outside contractors, and manufacturing, among others. This high level of control guides all departments to ensure that procedures and process are followed, with the ultimate goal being “integrity.”

Within any MOC or QA-QC system process control is of utmost importance. Critical processes need to be easily recognized as areas of extreme and exacting importance, including third party participation in pipeline integrity direct assessment.

Fundamentally, quality means the absence of deficiencies, i.e., conformance to specifications and adherence to procedural requirements. For a given activity, the internal QA-QC program identifies and addresses any missing or anomalous data. In most companies, there are multiple specialized departments or divisions; each one is responsible for specific functions, as well as to ensure that the work is performed as specified and documented. Systems should provide open lines of communication between all operational departments, procedural or otherwise, to encourage and foster total compliance.

While in some cases the MOC may simply be a procedural document, it will usually be part of the QA-QC system and, subject to the same control and audit requirements as all other departmental procedures, documentation, maintenance, and control. Each department’s procedures and their adherence to established plans and processes should be audited and statistically monitored annually. In general, audits of any internal QA-QC or MOC system should be random and unannounced. Departments should have only minimal opportunity to “prepare” for any audit. MOC and QA-QC documentation should be well established, organized, current and functional on an ongoing basis.

The absolute necessity for proper and comprehensive documentation must be stressed. Third party audits, regulatory or otherwise, will expect and demand full documentation of procedures and policies regarding, including at a minimum, the following:

- Processes and Procedures – proof of system reliability and level of control
- Physical condition of the pipeline and methods/processes continual and in place to measure/monitor these conditions
- Methodology/rationale governing all risk analysis and risk assessment processes and statistical outcomes
- Historical and current maintenance and repair records whether mechanical, electrical, procedural – where, when, why and how

It is vitally important to adhere to the technical, physical and procedural components of the MOC system. This is what ensures the proper working structure of the company's IMP under the control of the company's main QA-QC system. These guidelines are meant to govern not only personnel directly employed by the operating company, but contract personnel who are considered indirect employees of the company. It is the responsibility of those who manage the QA-QC and MOC programs to maintain accurate and current records regarding qualifications and work output of contract personnel. The QA-QC system exists to guarantee that the procedural guidelines are followed by all and these controls ensure the proper function of the MOC process and ultimately a well controlled and documented Integrity Management Program.

12.1.5 Integrity Management Plan – Sample Outline

1 INTRODUCTION

1.1. Federal and State IMP Rules

1.1.1. Federal Regulation Governing Interstate Pipelines

1.1.2. Intrastate Pipelines and Jurisdictional Gathering Lines

3.1.6.Typical Data Sources

3.2. Risk Ranking and Assessment Schedule

3.2.1.Risk Assessment Model

3.2.2.Segmentation Description

3.2.3.Segment Priority Report and Schedule

3.2.4.Future Risk Ranking Activities

3.2.5.Use of Pipeline Risk Profiles

3.2.6.Risk Model Validation and Improvement

3.2.7.Documentation

3.2.8.Validation of Results

3.2.9.Facilities

4 ASSESSMENT PLAN

4.1. Integrity Assessment Plan Hazardous Liquid Systems

4.1.1.Assessment Plan

4.1.2.Assessment Methods

4.1.3.Assessment Plan Update

4.1.4.Change in Circumstance

4.1.5.Newly Identified HCAs

4.1.6.Changes to the Assessment Plan

4.2. Integrity Assessment Plan Gas Transmission Systems

4.2.1.Assessment Plan

4.2.2.Assessment Methods

4.2.3.High Risk Segments

4.2.4.Assessment Plan Update

4.2.5.Direct Assessment Requirements

4.2.6.Change in Circumstance

4.2.7.Newly Identified HCAs

4.2.8.New Construction

4.2.9.Consideration of Environmental and Safety Risks

4.2.10.Documentation Requirements

4.3. Assessment Plan State Jurisdictional Pipelines

4.3.1.DOT/State Jurisdiction

4.3.2.Risk based vs. Prescriptive

4.3.3.Assessment Method Selection State Liquid Systems

4.3.4.Assessment Method Selection State Natural Gas Systems

4.3.5.Change in Circumstance

4.3.6.Documentation Requirements

FORM 4.1: Assessment Method Selection

5 PIPELINE REPAIR AND REMEDIATION PLAN

5.1. Hazardous Liquid Systems

5.1.1.Review and Analysis of Assessment Results

5.1.2.Qualification Requirements for Personnel Evaluating Assessment Results

5.1.3.Discovery of a Condition

5.1.4.Evaluation of Results

5.1.5.Repair/Remediation Scheduling Requirements

5.1.6. Changes to the Repair/Remediation Plan

5.1.7. Repair/Remediation Criteria

5.1.8. Repair Methods

5.1.9. Permitting and Access Requirements

5.1.10. Documentation Requirements and Responsibility

5.2. Gas Transmission Systems

5.2.1. Review and Analysis of Assessment Reports

5.2.2. Qualification Requirements for Personnel Evaluating Assessment Results

5.2.3. Discovery of a Condition

5.2.4. Evaluation of Results

5.2.5. Repair/Remediation Scheduling Requirements

5.2.6. Changes to the Repair/Remediation Plan

5.2.7. Repair/Remediation Criteria

5.2.8. Repair Methods

5.2.9. Permitting, Environmental Protection, and Access Requirements

5.2.10. Documentation Requirements and Responsibility

5.3. Texas Systems

5.3.1. Review and Analysis of Assessment Reports

5.3.2. Discovery of a Condition

5.3.3. Gas Transmission and Jurisdictional Gathering Systems

5.3.4. Hazardous Liquid Systems

7.1.1. Preventative and Mitigative Measures Evaluation

7.1.2. Preventative and Mitigative Measures Implementation

7.1.3. Leak Detection

7.1.4. Automatic Shut Off or Remotely Operated Valves

7.1.5. Facility Preventive and Mitigative Measures

7.1.6. Documentation Requirements

7.2. Gas Transmission Systems

7.2.1. Preventative and Mitigative Measures Evaluation

7.2.2. Preventative and Mitigative Measures Implementation

7.2.3. Third Party Damage

7.2.4. Outside Force Damage Monitoring

7.2.5. Automatic Shut off Valves

7.2.6. Corrosion

7.2.7. Pipelines Operating Below 30% SMYS

7.2.8. Documentation Requirements

FORM 7.1: Preventatives and Mitigation Measures

8 MANAGEMENT OF CHANGE PLAN

8.1. Management of Change Applicability

8.2. Management of Change Process

8.2.1. Minimum Information Requirements for Management of Change

8.2.2. Management of Change Process Flow

FORM 14.1: Revision Request Form

15 GLOSSARY

15.1. Abbreviations and Acronyms

15.2. Integrity Terms & Definitions

15.3. References

15.4. Cautions, Warnings and Other Notes

Appendix A: HCA Identification Process

Appendix B: Risk Analysis

Appendix C: Risk Algorithm

Appendix D: References

Appendix E: Integrity Assessment Procedures

Appendix F: Assessment Plan

Appendix G: HCA Maps (See HCA Map Book)

Chapter 13: Management Perspectives

After completing this chapter, students should:

- Be able to articulate the management responsibility and potential civil and criminal indictments that could result from management inattention to their Pipeline Corrosion Integrity Management system.
- Be familiar with relevant case studies and understand thoroughly how what they have learned in the PCIM course can be put into practice.

Introduction

In today's business and legal environment, Pipeline Integrity should be a focus at the highest levels of management, including corporate officers and the board of directors, who have a fiduciary responsibility to operate the company in the best interest of the public, the investors and the employees. When pipeline integrity is compromised, the probability of leaks or spills increases exponentially. Oil or gas leaks have a highly deleterious impact on health, safety and the environment (HSE). Indeed, public safety and environmental concerns fuel the need to manage pipeline infrastructure effectively, and for stricter government regulations and industry standards to provide measuring sticks by which to comply.

Recognition of the societal impact of pipeline leaks has significantly elevated global focus on pipeline integrity. HSE concerns about pipeline accidents now drive government regulations worldwide.

The U.S. Department of Justice has made the pipeline industry the focus of increased environmental protection scrutiny supported by new laws providing powerful new prosecution tools to go after offenders. The U.S. government now holds individuals, including non-management technical personnel, criminally responsible for accidents arising from poor pipeline operations. Criminal indictments, felony convictions, fines and civil penalties cost pipeline companies millions of dollars following any reportable pipeline leakage. Even if the corporation is charged in the event of a failure resulting in a breach of public safety, corporate executives and technical personnel will not necessarily escape prosecution.

The direct costs of a pipeline failure are only a small fraction of the cost of a pipeline incident that releases product to the environment. Other costs include:

- Lost revenue from interruption of pipeline operations
- Lost product
- Expenditures for repair and the cost of property damage
- Public liability including increased insurance costs
- Public image including investor relations
- Civil and possibly criminal penalties
- Increased regulatory scrutiny

13.1 Case Studies

13.1.1 DG-ICDA, ECDA and ILI

13.1.1.1 Dry-gas Internal Corrosion Direct Assessment (DG-ICDA)

The first part of this case study is based on the investigation of a natural gas company to validate the DG-ICDA processes and procedures. The objectives of the study were to:

- Perform an internal corrosion assessment using DG-ICDA
- Confirm the applicability of DG-ICDA for assessing internal corrosion threats
- Optimize DG-ICDA procedures
- Compare the results to an in-line tool inspection

The segment of pipeline selected for the study was a 30 plus-year old carbon steel pipe located in Texas. It is 32 miles long, 8 inch diameter, with a 0.160 inch wall thickness. The service was normally dry, natural gas with less than 2% carbon dioxide and zero hydrogen sulfide.

Pre-Assessment

Operating history indicated that the pipeline had been idle for a period of four years before it was placed in service. While idle, the line had been treated with corrosion inhibitors. This situation did not preclude the use of DG-ICDA because the greatest extent of the internal corrosion would have occurred during the 20 plus years of operation prior to taking the line out of service and the three years of operation after being returned to service. Records indicated that methanol was occasionally injected when the line was in operation due to changing flow conditions. The flow of natural gas was in the same direction throughout the life of the pipeline.

As part of the pre-assessment, samples of internal residue were collected and analyzed. Solid samples contained black powder (iron sulfide) corrosion products. Some small amounts of amine and carboxylate chemical inhibitors were detected, as well as trace amounts of glycol and methanol

As a result of the pre-assessment, the pipeline segment was divided into two DG-ICDA regions with the demarcation at roughly the mid point.

13.1.1.2 DG-ICDA Indirect Inspection

The pipeline was located using a radio frequency pipe locator, marked every 100 feet and the depth-of-cover measurements recorded. GPS coordinates (X, Y and Z) were measured at each location using sub-meter DGPS. Because the elevation data is critical and must be accurate to determine inclination angles, elevation angles were calculated every 100 feet along the segment length. A real-time kinematics (RTK) GPS reference station was established at the beginning of the DG-ICDA region. Using radio-frequency communication with a stationary reference for error correction, sub-centimeter accuracy was achieved. At each GPS measurement location, the following data were recorded:

- Location
- Date
- Operator
- Antenna height

- Start/Stop time
- Number of satellites
- Latitude, longitude and elevation

Critical angles were calculated for each region and the corresponding pipeline operating conditions were recorded. For each of the DG-ICDA regions, the results were:

- Region 1 – 10.5° at 28 million cubic feet/day and a pressure of 800 psi.
- Region 2 – 8° at 18 million cubic feet/day and a pressure of 400 psi.

Error limits in measurement of pipe depth and elevation are much smaller than their impact on the critical angles and, therefore, do not have a significant impact on the calculation (an 8° critical angle corresponds to a rise of approximately 14 feet over a distance of 100 feet). Based upon the indirect inspection, five sites that exceeded the critical angle were selected for direct examination. Three sites were in DG-ICDA Region 1 (sites DG-ICDA 1, 2, 3) and two sites in Region 2 (DG-ICDA 4, 5). Control sites were later selected in conjunction with an in-line inspection and a subsequent ECDA.

13.1.1.3 DG-ICDA Direct Examinations

ICDA Site 1 is located in a mostly dry creek bed, between two hills, with only limited standing water. The depth of the line is approximately six feet. At this location, the pipe transitions from 0° to 10.5° over a distance of 62 feet (see Figure 13.1 Schematic of Pipe Elevation at DG-ICDA Site 1). Two excavations were performed where the pipe angled from 0° to1.5° and from 7° to 10.5° (see Figure 13.2). The first excavation exposed 11 feet of pipe and the second, 23 feet. The coating was removed and the pipe surface prepared to SSPC-3 Power Tool Cleaning using a wire wheel cleaning tool. A-scan ultrasonic thickness measurements were recorded on a two inch grid. There were no indications of internal corrosion detected.

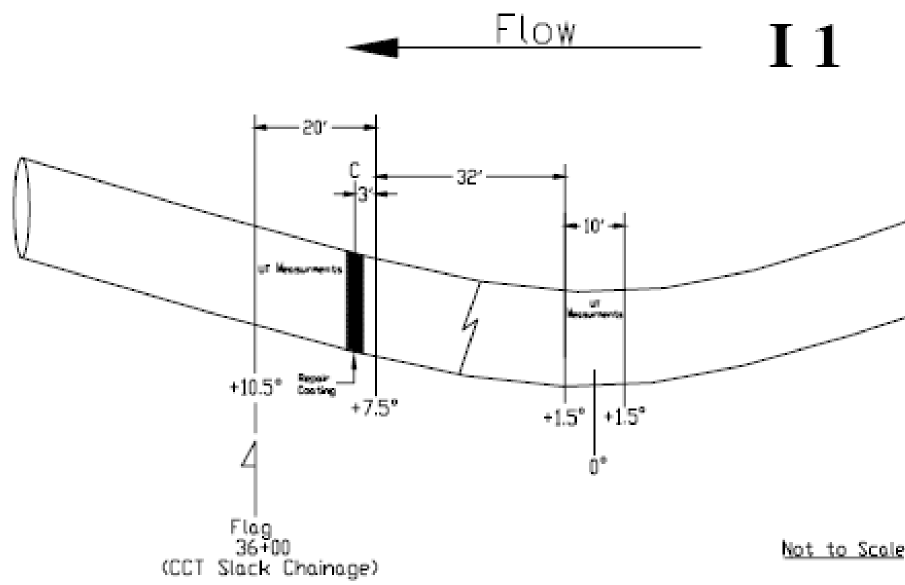

Figure 13.1 Schematic of Pipe Excavation for Site 1

ICDA Site 2 is located in a running creek between two hills. The depth of the line is approximately 5 feet. At this location, the pipe transitions from 0° to 10° over 97 feet (see Figure 13.3). The excavation exposed 66 feet of pipe where the coating was removed and the pipe surface prepared using a wire wheel cleaning tool (see Figure 13.4). A-scan ultrasonic thickness measurements were recorded on a two inch grid over 25 feet of the exposed pipe. There were no indications of internal corrosion detected.

Figure 13.2 Excavation at DG-ICDA Site 1

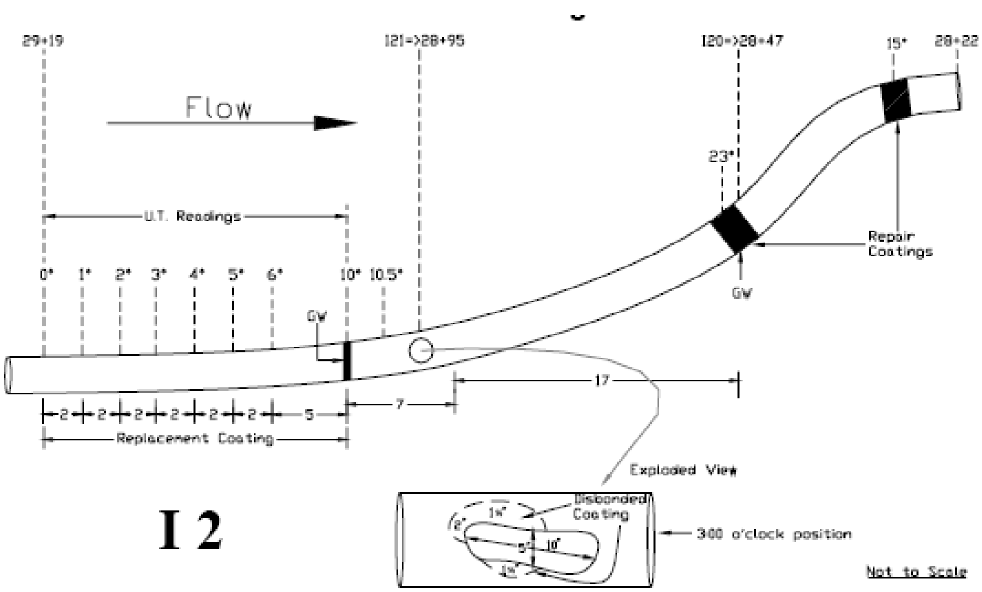

Figure 13.3 Schematic of Pipe Elevation at DG-ICDA Site 2

Figure 13.4 Excavation at DG-ICDA Site 2

ICDA Site 3 is located in a running creek between two hills. The depth of the line is approximately 4 feet (see Figure 13.5). The excavation exposed 66 feet of pipe where the coating was removed and the pipe surface prepared (see Figure 13.6). A-scan ultrasonic thickness measurements were recorded on a two inch grid over 30 feet of the exposed pipe which detected no indications of internal corrosion.

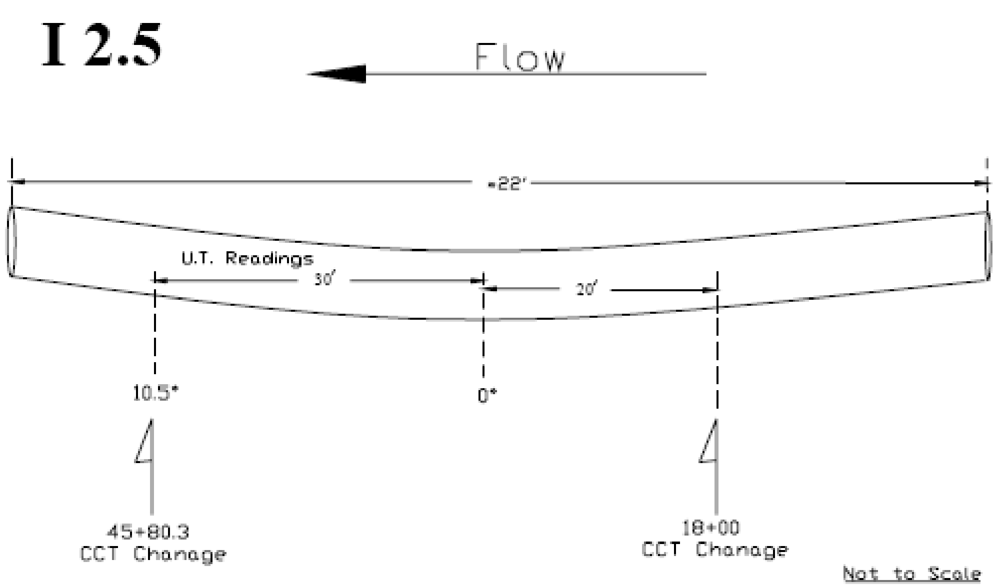

Figure 13.5 Schematic of Pipe Elevation at DG-ICDA Site 3

Figure 13.6 Excavation at DG-ICDA Site 3

ICDA Site 4 is located in a running creek between two hills. The depth of the line is approximately 4 feet (see Figure 13.7). The excavation exposed 36 feet of pipe where the coating was removed and the pipe surface cleaned to SSPC SP-3 (see Figure 13.8). A-scan ultrasonic thickness measurements were recorded on a two inch grid over 21 feet of the exposed pipe. No internal corrosion was detected.

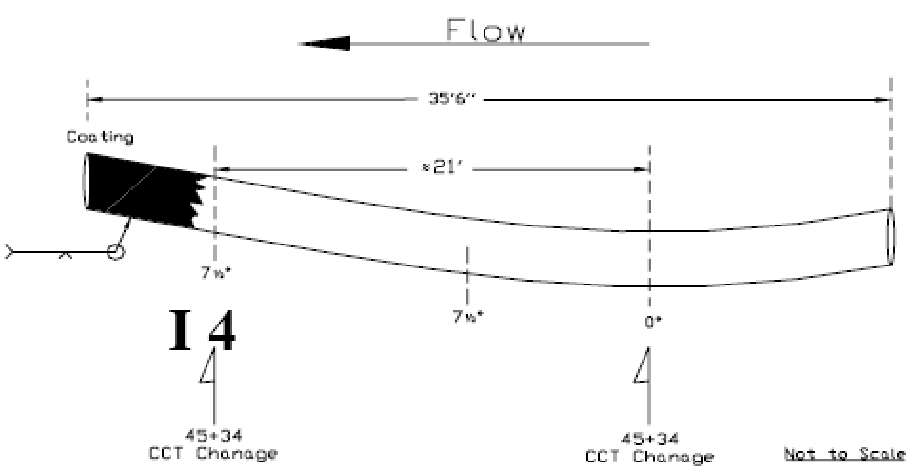

Figure 13.7 Schematic of Pipe Elevation at DG-ICDA Site 4

Figure 13.8 Excavation at DG-ICDA Site 4

DG-ICDA Site 5 is located in a running creek in a flat, grassy area where the pipe then continues at a 12° angle of inclination. The depth of the line is approximately 9.5 feet (see Figure 13.9). The excavation exposed 25 feet of pipe where the pipe ditch filled with approximately three feet of water (see Figure 13.10). The coating was removed and the pipe surface prepared for testing. A-scan ultrasonic thickness measurements were recorded on a two inch grid over 11 feet of the exposed pipe which detected no indications of internal corrosion. The direct examinations can be summarized as follows:

The conclusions of the DG-ICDA Direct Examination were:

- There was no corrosion detected at locations most likely to accumulate water.
- It is unlikely that there is internal corrosion in the remainder of the segment.
- No additional direct examinations were necessary.

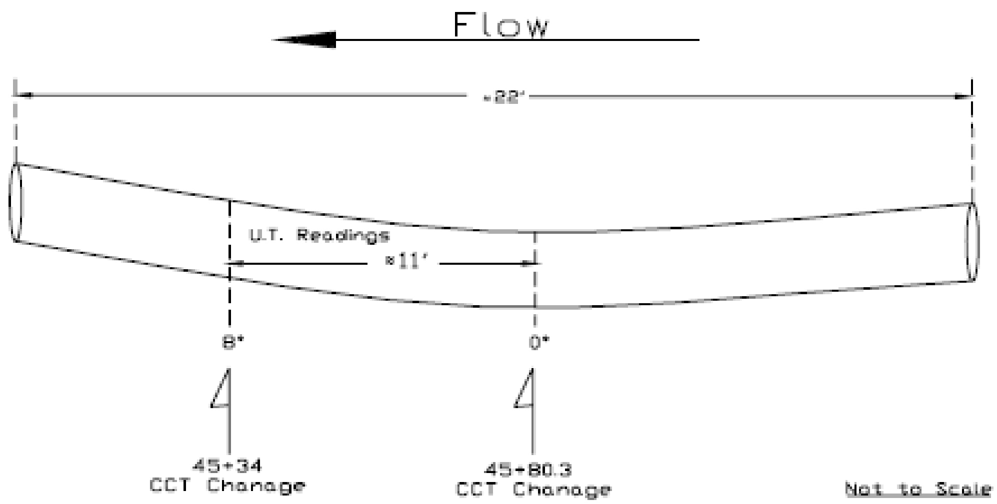

Figure 13.9 Schematic of Pipe Elevation at DG-ICDA Site 5

Figure 13.10 Excavation at DG-ICDA Site 5

Table 13.1: Tabular Representation of ICDA Direct Examination

S/N	Excavation	Length of UT Inspection, feet	Inclination Angle, degrees	Wall Thickness, inches
1	Site 1	10	0 to 1.5	0.148 to 0.161
2	Site 1	20	7.5 to 10.5	
3	Site 2	25	0 to 10	0.147 to 0.162
4	Site 3	30	0 to 10.5	0.145 to 0.161
5	Site 4	21	0 to 7.5	0.147 to 0.161
6	Site 5	11	0 to 8	0.149 to 0.163

Post Assessment

DG-ICDA was shown to be applicable as validated by running a high resolution, MFL in-line inspection (see below).

The maximum corrosion rate is less than 2 mpy in the presence of water as calculated by the dry gas model. The controlling factor in determining the reassessment interval was the external corrosion rate of 7 mpy, requiring a 9 year interval.

13.1.1.4 External Corrosion Direct Assessment (ECDA)

For completeness, ECDA was performed over the same section of pipeline with the following excavation determinations: 8 ECDA direct examinations and 3 control examinations.

13.1.1.5 In-Line Inspection (ILI)

An ILI inspection using high resolution MFL was performed throughout the pipeline segment. The log indicated problems with the odometer system over 4.42 miles where no data was recorded. This did not, however, impact the remainder of the inspection. The ILI tool vendor attributed the problem to debris in the pipeline.

The ILI log identified 30 anomalies that needed to be excavated and examined:

- Seven (7) external metal loss
- Seven (7) internal metal loss
- Two (2) internal anomalies, possibly dents

- Ten (10) internal anomalies, possibly mill related
- Three (3) dents
- One (1) possible dent associated with metal loss

The results of the anomaly examination and classification were:

- 65% of the anomalies were correctly classified
- 15% of the anomalies were incorrectly classified
- 20% of the anomalies were false indications
- Six (6) excavations required pipe repairs

At one location, the ILI indicated a number of anomalies including two (2) dents, one (1) external indication, four (4) mill defects and seven (7) internal pits located along the pipe invert.

Note that this was not a location where liquids would have collected inside the pipe. The pipe was excavated and a section removed. An internal examination revealed a group of pits, with the deepest at 65% through wall penetration. The internal pitting found at this location was not consistent with dry-gas internal corrosion due to several factors:

- The pitting location was isolated and not widespread
- The point was downstream from where gas was injected
- The location was not at a point of liquid accumulation

The following possible causes for this were examined as follows:

- A previously corrosive conditions caused by wet-gas

  This was concluded to be unlikely because of the localized pitting. Corrosion caused by wet-gas would be much more wide spread

- The corrosion could have occurred when the line was out of service and chemically inhibited

  This was concluded to be unlikely because of the localized pitting. This too is unlikely due to the concentration of the pitting

- The corrosion occurred prior to installation or during previous service

  This was determined to be the most likely explanation and it was also supported by observations from ECDA.

As a result of this comprehensive program of investigation, the pipeline operator concluded that:

- ICDA determined that significant internal corrosion from periodic accumulation of water is unlikely in the pipeline segment under study. This conclusion was supported by the field examinations of the pipe and the in-line inspection.
- ICDA was validated as an integrity verification and management tool for normally dry-gas pipelines.
- ICDA demonstrated that internal corrosion from gas operations is not considered significant for this pipeline.
- Available pigging technology is not foolproof in assessing pipeline integrity.

Acknowledgement: This case study is excerpted from a presentation by Drew Hevle, Senior Corrosion Engineer, Enbridge Energy Inc. at the NACE International Pipeline Integrity, Direct Assessment Seminar, January 11-12, 2006, Houston, Texas.

13.1.2 External Corrosion Direct Assessment (ECDA)

A gas company operates 212 miles of DOT reportable transmission lines subject to the pipeline integrity rule. The lines are located in congested areas on the east coast of the United States as follows:

Table 13.2: ECDA Case Study Data

State	Miles
Virginia	105
Maryland	69
District of Columbia	20
West Virginia	18

The pipeline system overview is presented in Figure 13.11.

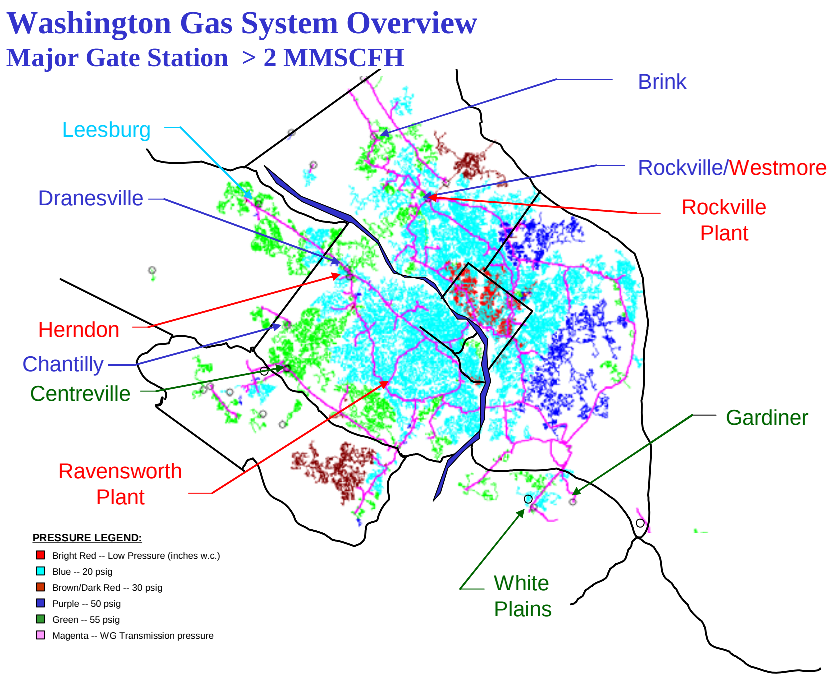

Figure 13.11 System Overview

Within the 212 miles of transmission lines, High Consequence Areas (HCAs) were determined by a virtual survey within Smallworld using the Potential Impact Circle (PIC) method. Prior to calculating the potential impact radius, the accuracy of the following information was considered:

- Building Class attributes were accurately presented in Smallworld that could affect the HCA analysis
- Using aerial data, identified site polygons were created as defined by 49 CFR 192, Subpart O
- Confirmed location of the pipeline segment

The PIC approach calculates the impact radius based upon the following pipeline attributes:

- Pipeline diameter
- Maximum allowable operating pressure (MAOP)

- Constant of 0.69 for natural gas

Based upon the analysis, 84 miles of pipeline were in identified high consequence areas. ECDA was chosen to perform the baseline assessment for one of the pipeline segments.

Pre-Assessment

The pipeline segment consists of approximately 8.8 miles within one HCA. It is 24 inched in diameter, with an MAOP of 240 psi, installed 50 years ago. Over its life there have been three (3) replacement offsets. Two of these are 220 feet and 37 feet along highly traveled streets. The third is 370 feet long, installed in 1970, with a deep vertical drop to get down to street level from an elevated freeway.

The ECDA pipeline segment is almost entirely underneath 18-inch thick, reinforced concrete roads that have been overlaid with asphalt. The area is congested and highly traveled (see Figure 13.12). There is a good history of cathodic protection of the pipeline segment. The pipeline segment was divided into four (4) sections based on positioning of isolation flanges. It was treated as one ECDA region because of the similar environmental conditions surrounding the piping. The pipe is approximately 6 feet below soil surface.

13.1.2.1 Indirect Inspection

The following indirect inspection techniques were considered:

- Close Interval, Pipe-to-Soil Potential Survey (CIS)
- Direct Current, Voltage Gradient Survey (DCVG)
- Alternating Current, Voltage Gradient Survey (ACVG)
- AC Current Attenuation (ACCA)

CIS and DCVG techniques were selected for use along with depth of cover and GPS measurements. Holes were drilled at 7.5. foot intervals to contact the underlying soil to collect accurate, meaningful data. Approximately 4,400 holes were needed (see Figure 13.13 and Figure 13.14).

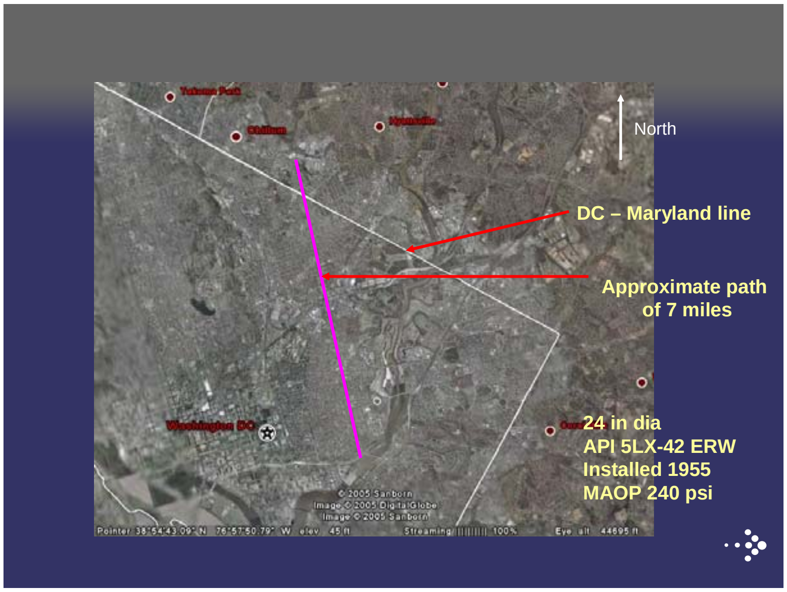

Figure 13.12 ECDA Segment

Figure 13.13 Traffic Control for Indirect Inspections

Figure 13.14 Marking Hole Location for Indirect Inspection

Based on the indirect inspections there were four (4) anomalies found in four (4) locations. In addition to performing direct examinations (digs) at these locations, NACE SP0502 requires two (2) "null" digs making a total of six (6) digs.

13.1.2.2 Direct Examinations

The Direct Examination phase of the project consisted of:

1. Excavating the Pipe
   - Cutting concrete
   - Removing soil
   - Shoring

2. Data collection
   - SCC, MIC testing
   - Soil and water sampling
   - pH, pipe-to-soil potential and resistivity measurements

3. Assessing coating
   - Coating type, condition, adhesion
   - Coating removal, testing water pH under coating

- Collection of corrosion products

4. Measurement of pipe defects
   - Ultrasonic wall thickness measurements
   - Evaluation of corroded areas, pit depth, configuration
   - Crack assessment, magnetic particle, dye penetrant method

5. Evaluation of remaining strength
   - RSTRENG
   - ASME B31G
   - Modified ASME B31G
   - DNV Standard RP-F101

6. Prioritization
   - Immediate action required
   - Scheduled action required
   - Suitable for monitoring

7. Root cause analysis

At the first indirect inspection anomaly, a large tree stump was in contact with the pipe (see Figure 13.15). This was corrected and the pipe recoated.

Figure 13.15 Tree Stump on Pipe

At the second anomaly, an 8 inch water, 24 inch water and 8 inch gas distribution line were in close proximity (see Figure 13.16). Their presence caused the changes in pipe-to-soil potential detected during the CIS. At the third anomaly, a 2-inch service connection was responsible for potential changes (see Figure 13.17). At the fourth anomaly, the coating was in poor condition (see Figure 13.18). The pipe was inspected and the area recoated.

Figure 13.16 Foreign Pipelines in Close Proximity

Figure 13.17 Two Inch Service Connection

Figure 13.18 Damaged Coating

Post Assessment

The project demonstrated that ECDA was an effective tool for assessing pipeline integrity. The definition of the pipeline segment and the indirect inspection techniques employed were valid.

There were many lessons learned in this project that will be helpful in future ECDA projects under pavement in congested areas:

- D.C. transit systems cause stray currents that need to be addressed during an ECDA project.
- Overhead AC transmission lines can cause induced voltages on the pipeline that may affect survey techniques and/or require additional filtering for collection of accurate measurements.
- Projects are complicated further when there are two jurisdictions involved (in this case Washington D.C. and Maryland).
- Crossings of other pipelines (e.g., water, gas distribution) need to be identified as well as metal jacketed power and communications cables.
- Street permits and procedures for closing streets need to be thoroughly understood and addressed prior to commencement of field operations.
- The logistics of traffic control and drilling of test holes through the pavement are a part of the process that needs to be carefully planned.
- There may be restrictions as to the hours where traffic lanes and streets can be closed and when pipeline excavations can be made.
- Provisions need to be made to address abandoned and parked cars.
- Line location and alignment is critical to the success of the project including collection of GPS data to facilitate data integration.
- Excavation and shoring procedures should be documented and should comply with OSHA requirements.
- The jurisdiction may have procedural requirements for backfilling excavations and handling excavated material. In cases where the same dirt could not be used to backfill, the excavated mate-

rial should be directly placed in the truck without contacting the ground, and the excavation should be backfilled with imported material.

- The reassessment interval was calculated in accordance with NACE SP0502 and determined to be twenty (20) years with confirmatory direct assessments required in seven (7) and fourteen (14) years.

Acknowledgement: This case study is excerpted from a presentation by Susan Borenstein, Pipeline Integrity Engineer, Washington Gas at the NACE International Pipeline Integrity, Direct Assessment Seminar, January 11-12, 2006, Houston, Texas.