DIRECT ASSESSMENT TECHNIQUES FOR INTEGRITY MANAGEMENT OF UNDERGROUND PETROLEUM PIPELINES

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Outline

Pipeline Integrity

- Pipeline Integrity Management
- Integrity Assessment Tools

Direct Assessment

- Pre-assessment
- Indirect Inspection
- Direct Examination
- Post-assessment

Summary

Pipeline Integrity

- Pipeline Integrity Management
- Differences between Natural Gas and Hazardous Liquid Pipelines
- Threats to Pipeline Integrity
- Pipeline Integrity Assessment
- Direct Assessment

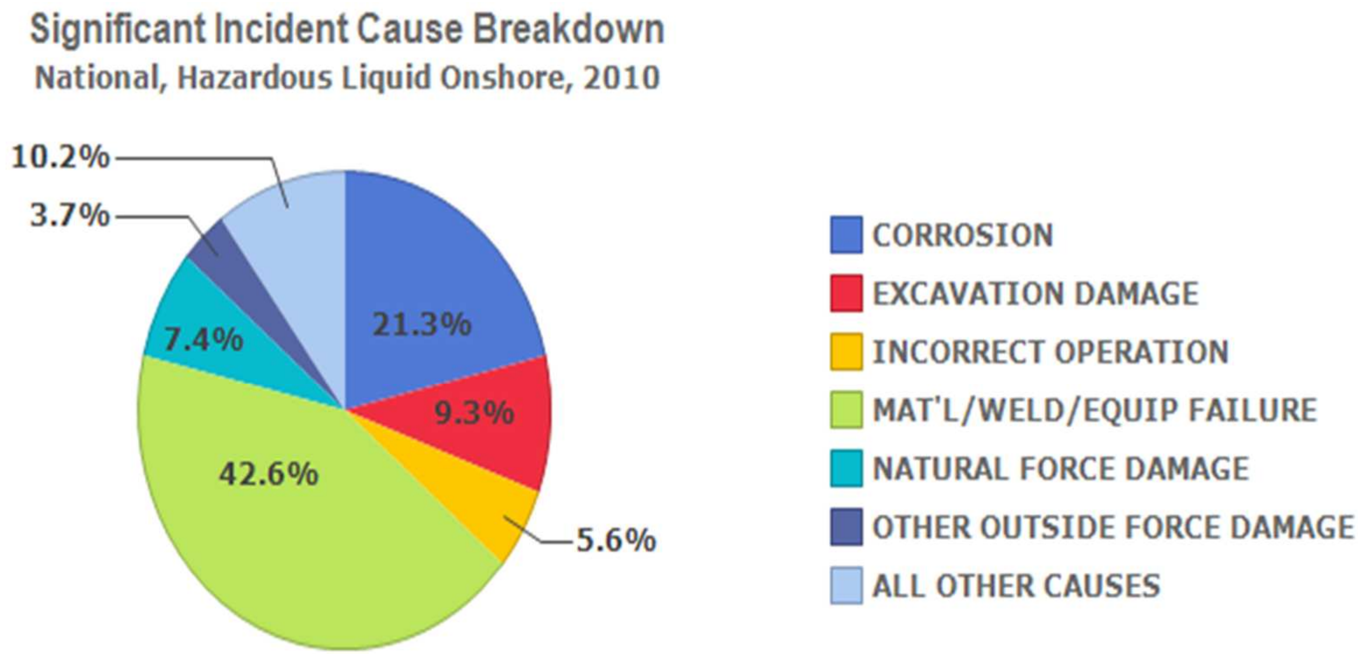
Pipeline Integrity Management (PIM)

- The Primary Goal of every Pipeline System Operator is to:
  - Provide safe and reliable delivery of the product to customers, without adverse effects on employees, the public, customers, or the environment.
- An Effective Pipeline Integrity Management Program:
  - Provides information for an operator to effectively allocate resources for an appropriate prevention, detection, and mitigation activities,
  - That will results in improved safety and a reduction in the number of incidents
- Relates to a pipeline's compliance with applicable regulations and standards

US Pipelines Statistics

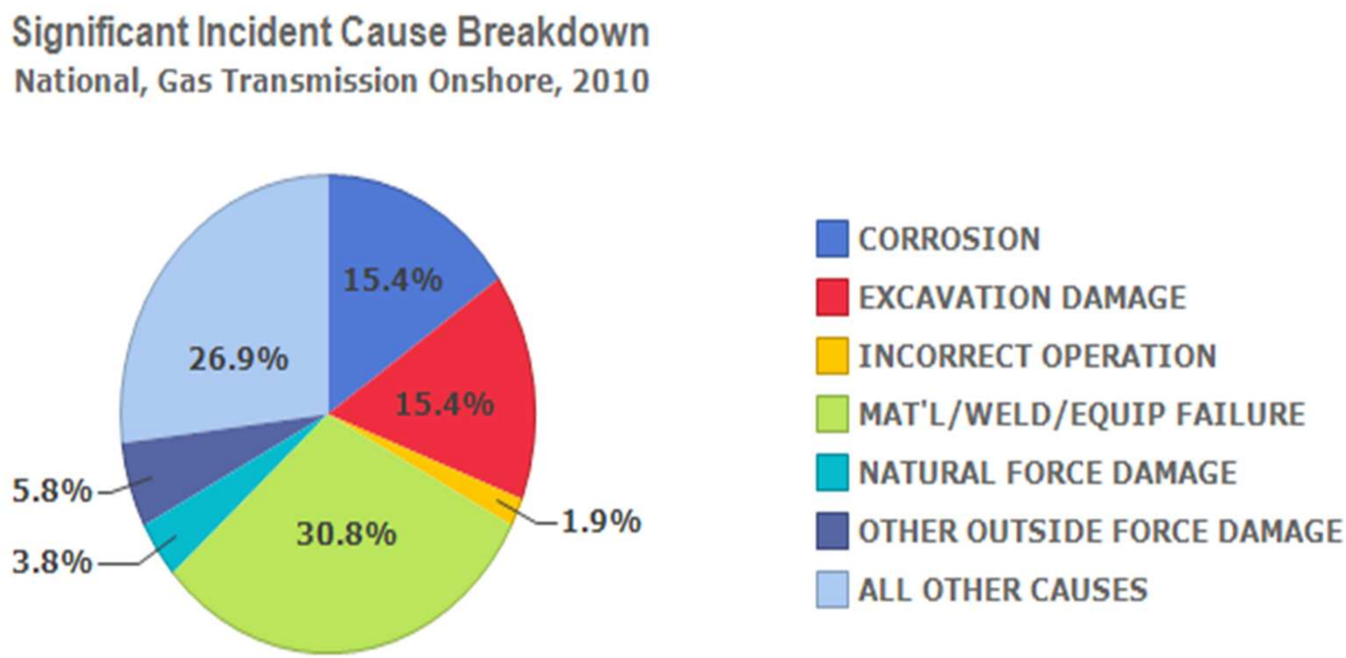
- The Department of Transportation, Office of Pipeline Safety post incident reports on their web page (http://primis.phmsa.dot.gov)
  - There are 321,000 miles gas transmission lines (onshore and offshore)
  - There are 175,000 miles liquids pipelines (onshore and offshore)
- For the period 1/1/1991-12/31/2010:
  - 864 significant incidents (43 fatalities) onshore gas transmission
  - 2,681 significant incidents (40 fatalities) onshore liquid pipelines
- For the year 2010 (alone):
  - 52 significant incidents (10 fatalities) onshore gas transmission
  - 108 significant incidents (1 fatality) onshore liquid pipelines

Hazardous Liquid Pipelines Onshore



Source: PHMSA Significant Incidents Files March 1, 2011

Gas Transmission Pipelines Onshore



Source: PHMSA Significant Incidents Files March 1, 2011

Hazardous Liquid and Gas Transmission PIM

- Process used to ensure continued operation safely and meeting all applicable regulations
- PIM takes into consideration all relevant codes, standards, and regulations
- Liquid hazardous pipelines:
  - Standard: API 1160
  - US Regulation: 49CFR195, Subpart F Paragraph 195.452
- Gas transmission pipelines:
  - Standard: ASME B31.8S
  - US Regulation: 49CFR192, Subpart O

Pipeline Integrity Threats

- Gas Pipeline incidents data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes.
- One of the 22 causes was reported by operators as “unknown” (no root cause or causes were identified).
- The remaining 21 threats have been grouped into (9) categories of related failure types, and
- Delineated by three time-related defects types

Stable Threats

- Manufacturing Related Defects
  - Defective pipe seam
  - Defective pipe
- Welding/Fabrication Related
  - Defective pipe girth weld
  - Defective fabrication weld
  - Wrinkle bend or buckle
  - Stripped threats/broken pipe/coupling failure
- Equipment
  - Gasket O-ring failure
  - Control/Relief equipment malfunction
  - Seal/pump packing failure
  - Miscellaneous

Time Independent Threats

- Third Party/Mechanical Damage
  - Damage inflicted by first, second , or third parties
  - Previously damaged pipe (such as dents and or gauges)
  - Vandalism
- Incorrect Operations

- Weather related and outside force
  - Cold weather
  - Lightning
  - Heavy rains or floods
  - Earth movements

Time Dependent Threats

- External Corrosion
- Internal corrosion
- Stress Corrosion Cracking
- Fatigue (not included)

Pipeline Integrity Assessment

- Pipeline Integrity Assessment is a process that includes:
  - Inspection of pipeline facilities,
  - Evaluating the indications resulting from the inspections,
  - Examining the pipe using a variety of techniques,
  - Evaluating the results of the examination,
  - Characterizing the evaluation by defect type and severity, and
  - Determining the resulting integrity of the pipeline through analysis

Pipeline Integrity Assessment Methods

- In-Line Inspection (Internal inspection)
- Pressure Test
- **Direct Assessment**
  - ECDA
  - ICDA – Dry Gas (DG), Liquid Petroleum (LP) and Wet Gas (WG)
  - SCCDA
- Other Technology

What is Direct Assessment?

- A method of assessing pipeline integrity.
  - Intended to be no less protective of public safety and environment than ILI or Hydrotest.
  - SCCDA may not replace ILI or hydrotest in many cases

- From “direct examination.”
  - Bell hole inspections.

Direct Assessment Process

- Utilize existing technologies in an integrated approach intended to map corrosion defects
- Utilize prediction modeling to determine “like and similar”
- Use results to safely manage the pipeline system

Direct Assessment Concept

- Technologies can be used as a diagnostic tool to assess pipeline integrity

- Defect growth models can be used to determine “safe” operating conditions and to determine re-assessment or inspection frequency

Direct Assessment Methodology

- Pre-assessment
  - Assembly and review of pipeline data
- Indirect Inspection
  - Location of Indications / Severity Classification
- Direct examination
  - Excavation, inspection, defect assessment
- Post-assessment
  - Validation, prioritize repairs, re-assessment intervals

Pre-assessment

- Data Collection:
  - Pipe
  - Construction
  - Corrosion Control
  - Soil / Environment
  - Operational

Pipe Grade: API 5L X65

Nominal Diameter: 16-inch

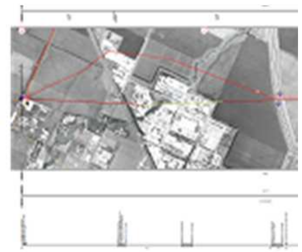
Wall Thickness: 0.288 inch

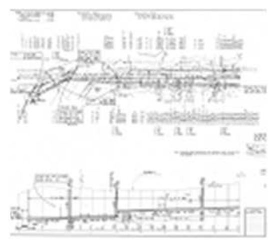
Year of Installation: 1941

Average Depth of Cover: 4 feet

Number of Steel Casings: 5

Cross-country pipeline





Pipe Coating: Coal Tar Enamel

Cathodic Protection: Impressed Current

Years without CP: 5

CP Records Available: Yes, since 1946

Topography: Mainly flat

Soil: Miamiam-Pewamo

Product: Natural Gas

Temperature: 80 F

Pressure: 850 psig

Leak: None

Pre-assessment Data DG-ICDA Essential Data

CATEGORY	DATA TO COLLECT
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., USGS 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—maximum and minimum 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 ˚C (130 ˚F) at compressor discharge 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.

Pre-assessment Data DG-ICDA Essential Data – cont'd.

CATEGORY	DATA TO COLLECT
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)?
Hydrotest information	Past presence of water, hydrotest water quality data.
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 and corrosivity, including the presence of bacteria, of the removed products.
Leaks/failures	Locations and nature of 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. 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.

Pre-assessment Results

- Feasibility of methodology to evaluate the impact of IC, EC and SCC on the integrity of pipeline
- SCC: Prioritize potentially susceptible segments and help select sites for excavations on those segments
- IC-DG: define sections between gas inputs where possibility of water entering the system exists.

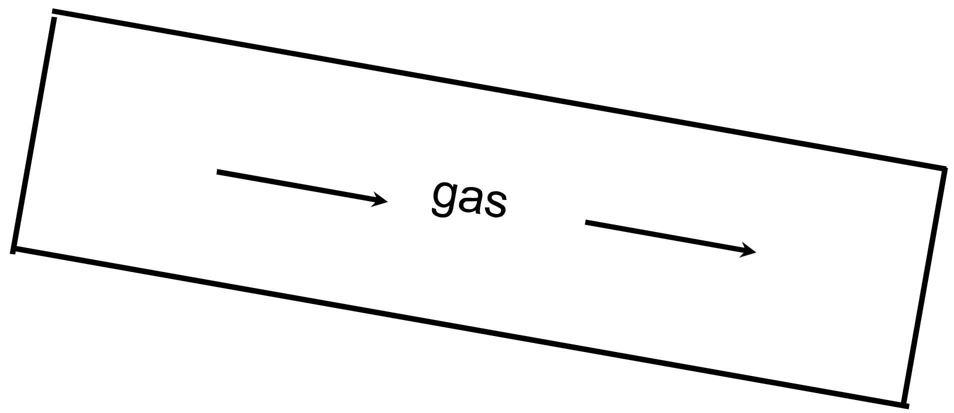
Pre-assessment Results – cont.

- IC-LP: Identify any parameter related to liquid petroleum constituents, flow patterns, operating conditions, or mitigative actions that may affect the location of corrosion initiation, corrosion mechanism, or anticipated corrosion rate
- EC:
  - Define sections with similar corrosion history
  - Define indirect inspection tools

Indirect Inspections

Line Location, Station, Depth of Cover & Current Attenuation	DCVG	CIS	GPS

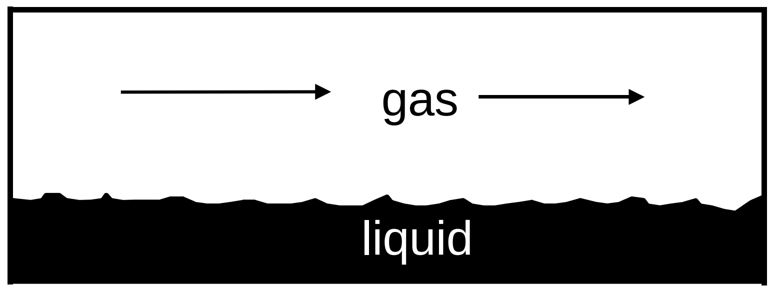
Flow Modeling Principles – DG-ICDA



- Gas flow and gravity drive liquid downstream
- No liquid holdup at <u>any gas velocity</u>

Max = 3864 mscf/hr, Avg = 1473 mscf/hr, Min = 494 mscf/hr, Mode = 1449 mscf/hr

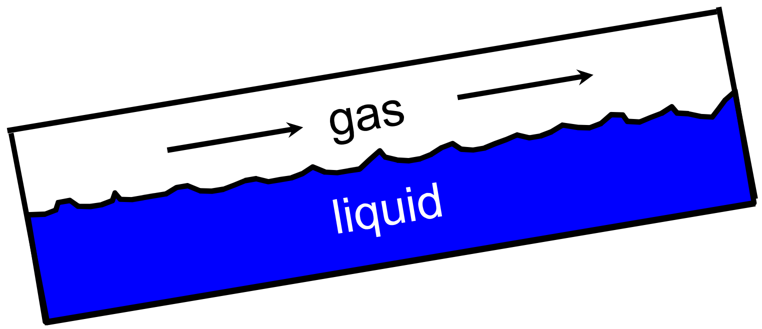
Flow Modeling Principles DG-ICDA



Zero Degree Inclination Angle ("completely" flat)

- Gas flow drives liquid downstream
- Gravity neutral
- Liquid holdup only occurs with <u>no gas flow</u>

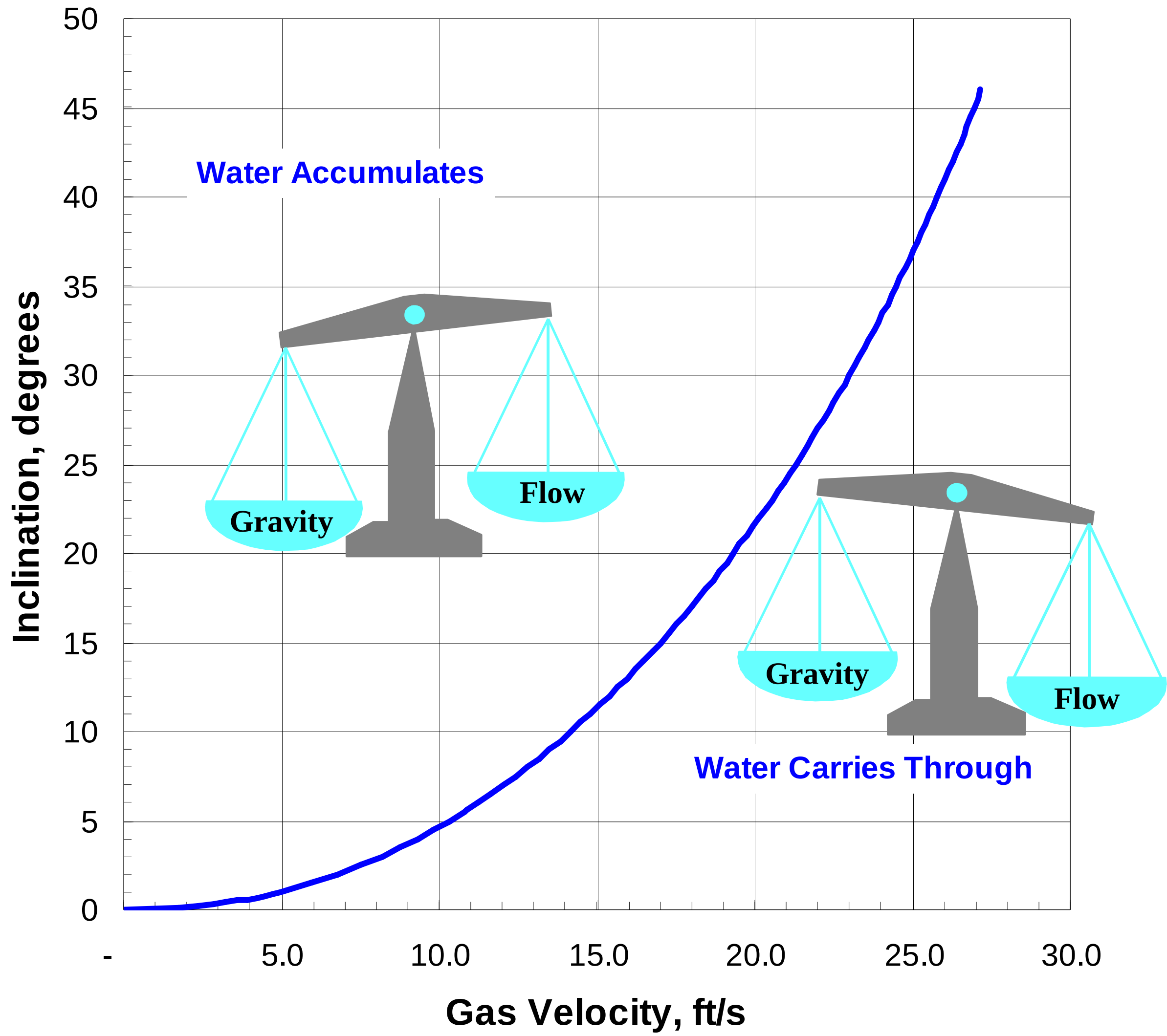
Flow Modeling Principles DG-ICDA



Positive Inclination Angle

- Gas flow drives liquid <u>down</u>stream
- Gravity drives liquid <u>up</u>stream
- Holdup depends on inclination <u>and</u> gas velocity

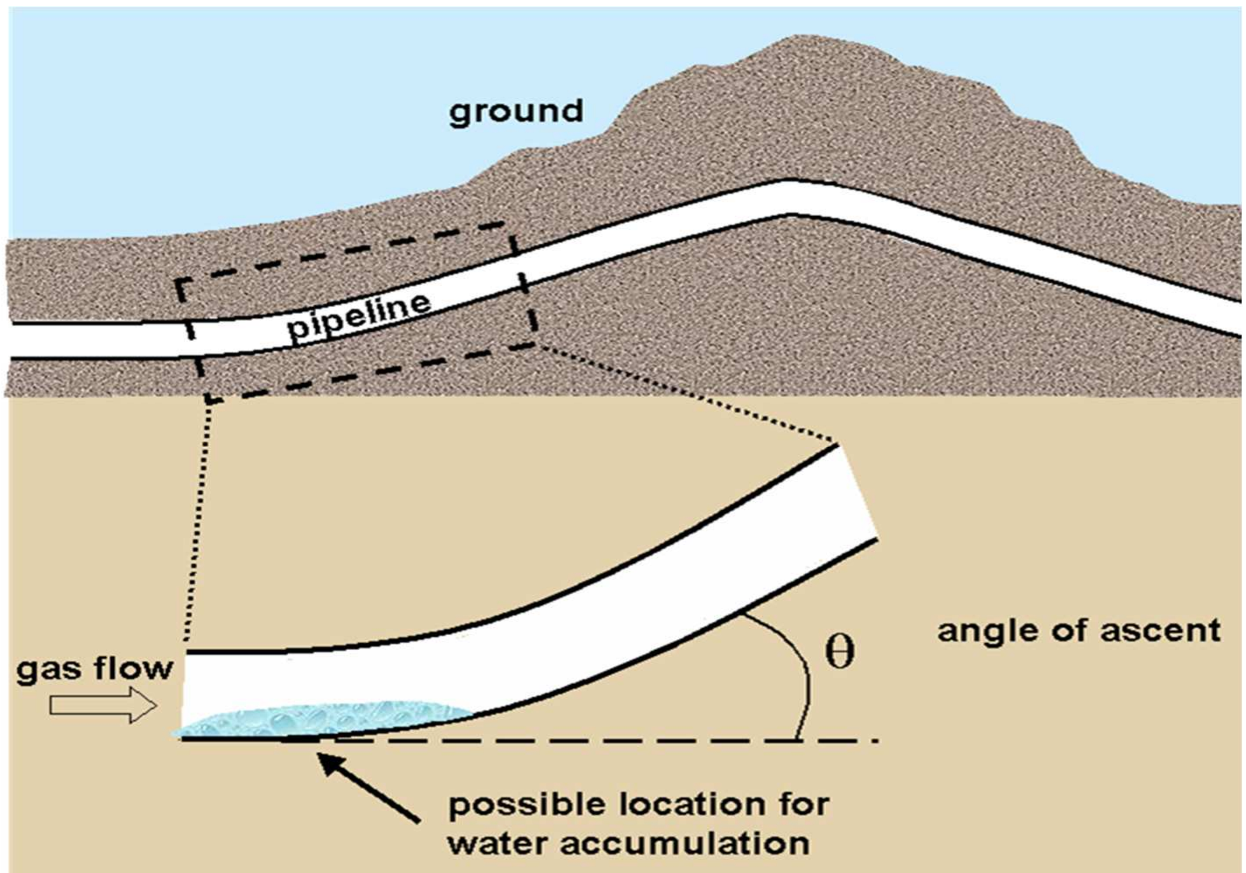
Critical Angle Versus Velocity



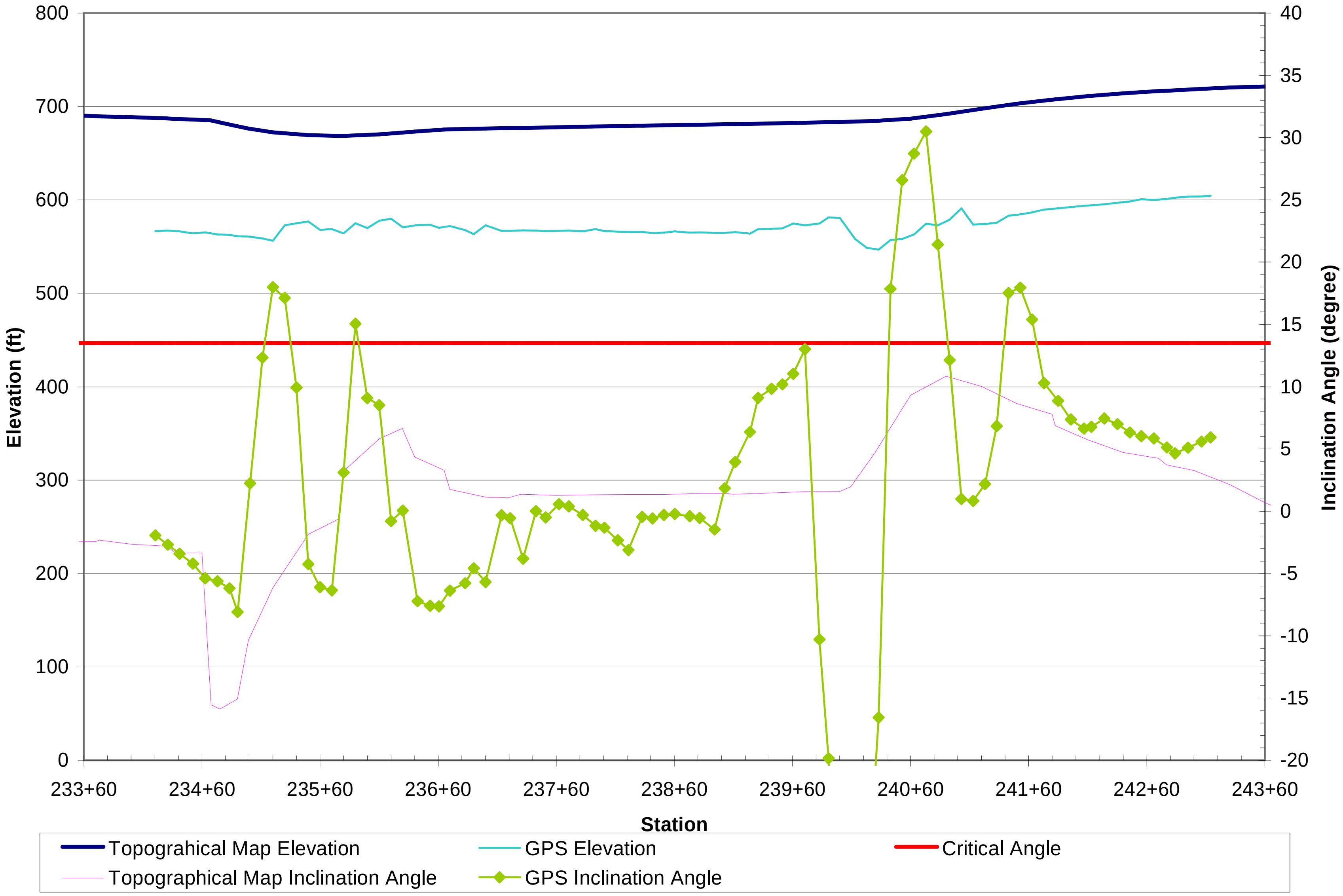
8 inch pipe at 4.1 MPa (600 psi) and 15.5°C (60°F)

DG-ICDA Example

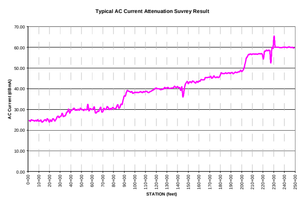
- Example location showing where water may collect

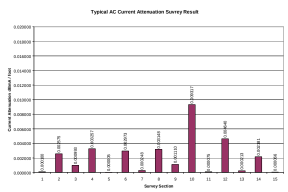


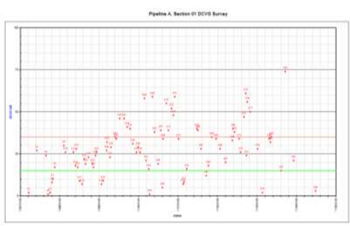
Indirect Inspections

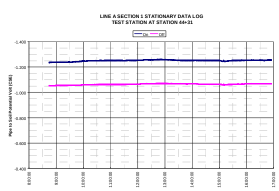


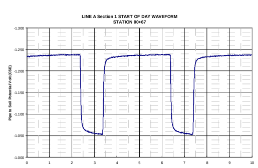
Data Alignment and Integration

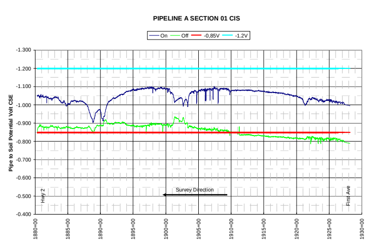


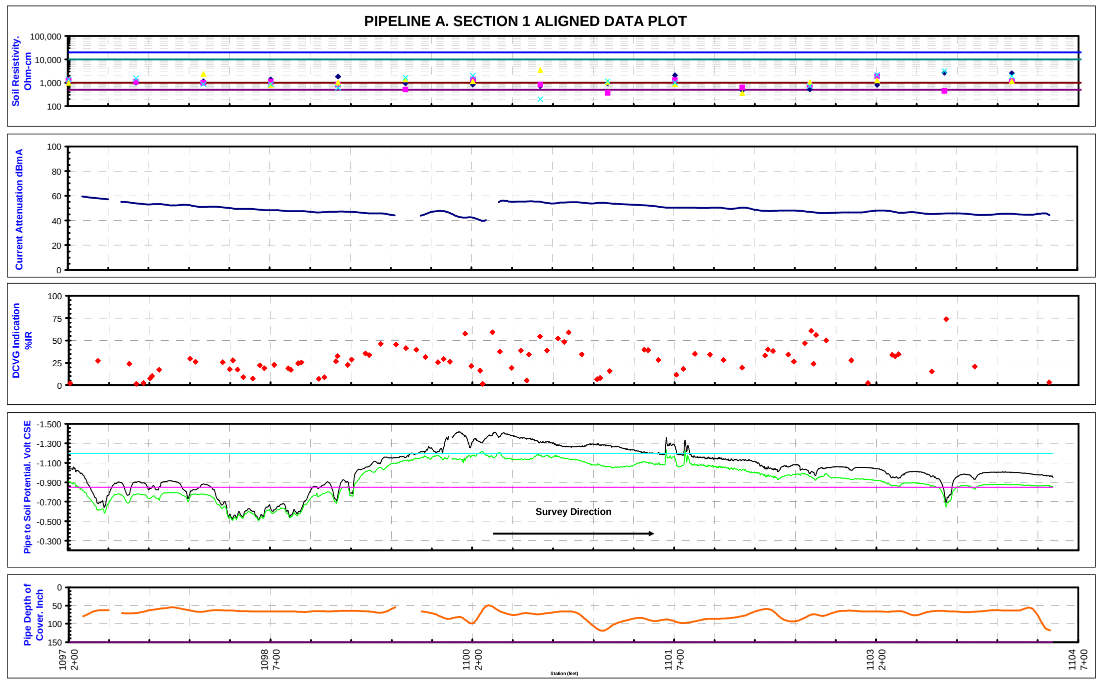












Direct Examination

Selection of Excavation Sites:

For SCCDA

- Give higher priority to larger diameter pipe
- Pipe with low fracture toughness or low tensile properties
- Highest priority – Low frequency ERW seam weld pipe
- Based on external coating – polyethylene tape higher
- Prioritize older pipeline segments

For ECDA and ICDA

- Prior corrosion history
- Results of Indirect Inspection

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Topography, Soil Type

Topography:

Soil

- Type
- Profile
- Drainage

Soil Samples

- Obtain at least four samples from each dig site
  - One at each end of the dig
  - One at 3:00 or 9:00 o'clock location near pipe
- Photograph soil samples and describe texture and color
  - Record any odors
  - Gray-black color and rotten egg smell usually indicate anoxic conditions
  - Tan color usually indicates oxic conditions

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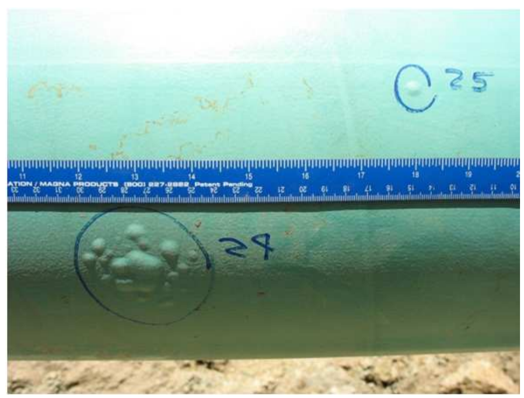
Coating Evaluation

- Coating Type: Asphalt, Coal Tar, FBE, Tape, Liquid Epoxy
- Type of Damage: Wrinkles, holidays, cracks, blisters, disbondment



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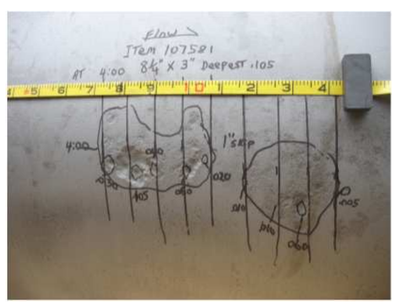
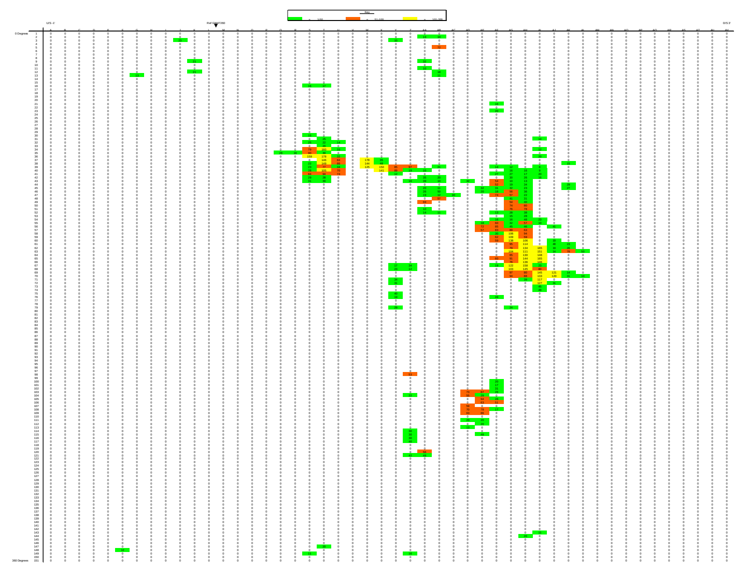
Pipe Surface Evaluation

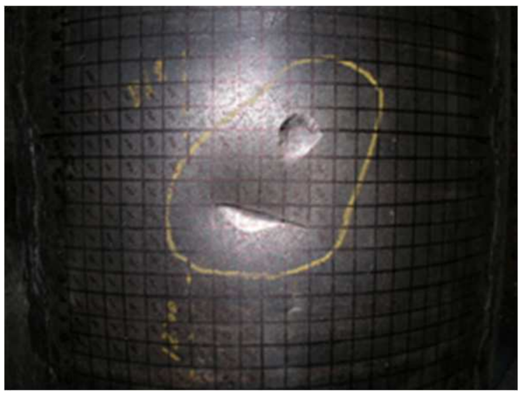
- Pipe Surface Damage:
  - External Metal Loss:
    - Type (morphology): General, localized, pitting, cracking
    - Measurements: Maximum depth, position, distance from reference point, mapping, UT wall thickness

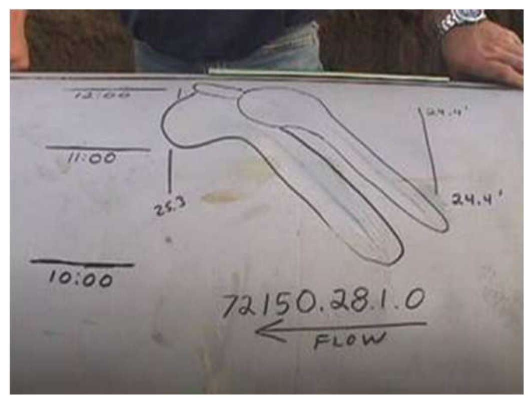




Pipe Surface Evaluation

- Pipe Surface Damage:
  - Mechanical Damage:
    - Type: Dent, Gauge, Wrinkle, arc burn
    - Measurements: Maximum depth, position, distance from reference point, mapping





Post Assessment

- Analysis of data from Steps 1 to 3
  - Determine whether SCC mitigation is required
  - Calculate remaining strength (metal loss)
  - Define and prioritize remedial actions, if required
  - Conduct Root Cause Analysis
  - Define re-inspection interval
  - Evaluate effectiveness of DA approach
  - Feedback and continuous improvement

DA Summary

- Pipeline Mechanical Integrity Assessment Methodology Similar to ILI and Hydrotesting
- 4-Step Process
- Indentifies areas where corrosion may have occurred or is occurring
- Prioritizes sites based on likelihood of ongoing corrosion and threat to the pipeline mechanical integrity
- Root cause analyses are conducted and mitigation plans are developed