THE BUSINESS CASE FOR PIPELINE INTEGRITY

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A transportation industry that moves energy in a safe and economical manner with competition from *Trains, Trucks, and Ships*
Pipeline Products

- Liquid vs. Gas
- High vs. Low Vapor pressures
- Refined vs. Raw products
- Hazardous (H2S)
- Corrosive
Keystone Pipeline
- $12 to $15/barrel of oil toll
- 830,000 bbl/day capacity
Pipeline Economics

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- $12 to $15/barrel of oil toll
- 830,000 bbl/day capacity

Assuming full capacity:
- $9,960,000/day revenue
- $3.6 billion/year tolls
- $13.6 billion/year cost of product (at $45/bbl)
“Moving oil and gas by pipeline was 4.5 times safer than moving the same volume the same distance by rail in the decade ended in 2013 in Canada, according to a new study by the Fraser Institute public policy think-tank.” Financial Post, August 2015
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“undiluted shipments of bitumen or heavy oil by rail is very competitive with pipelines being 12% to 31% less for rail versus committed pipelines. However, when diluent is added rail becomes uncompetitive.” Altex Energy study http://www.altex-energy.com/index.php/doing-business-with-us/93-doing-business/196-economics-of-rail-versus-pipeline
Construction and Operations Standards

- ASME B31.4 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
- ASME B31.8 - Gas Transmission and Distribution Piping Systems
- API 1110 - Pressure Testing Liquid Pipelines
- CSA Z662 - Oil and gas pipeline systems
Pipeline Design

Depends on:
1. Product to transport
2. Volume of product
3. Distance
4. Location
5. Pressure
6. Cost of materials & construction
Many mechanisms can result in a failure:

- Design Errors
- Manufacturing Defects
- Inappropriate site selection
- Construction Damage
- Incorrect Operations
- Third Party Damage
- Normal Operations – Corrosion and Fatigue
- Intentional damage
The Statistics

84% of CEPA failures related to Corrosion, 3rd Party & ROW

Summary of Incident Causes

ASME Causes of Gas Transmission Incidents

- Third Party Damage
- External Corrosion
- Internal Corrosion
- Natural Forces
- Misc
- Incorrect Operation
- Unknown
- Other Failures
- Constr/Instal
- Mfr
- Prev. Damgd Pipe
- Malfunction
- Stress Corrosion Cracking
- Vandalism

Causes of service ruptures experienced by CEPA member companies: 1985-1995

- General Corrosion (25%)
- Other (16%)
- SCC (17%)
- Geotechnical (19%) (landslides, etc.)
- Contact Damage (23%) (contact by earth moving equipment, etc.)
More Recent Data

More Recent Data

The direct cost of these accidents surpassed $600 million.

However, not considered was corporate share devaluation that in recent years may reach $billions, as in the 2010 Enbridge Marshal, Michigan Incident.

Pemex
Enbridge Line 6B – Marshall Michigan
Enbridge Line 6A

[Image of a rusted surface with a hole labeled '1.5 in.' and an arrow labeled 'Oil flow']
Pipeline Integrity - What is it?

• A structured management system to ensure that a pipeline network is
  – safe
  – reliable
  – sustainable and optimized
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  – safe
  – reliable
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• A North American concept with strong Canadian roots
Pipeline Integrity

*Includes all parts of the process:*

- Design
- Construction
- Operation
- Environment
- Social
Pipeline Integrity Threats

Time Dependent
1) External Corrosion.
2) Internal Corrosion.
3) Stress Corrosion Cracking.

Stable
4) Manufacturing Related Defects
   • Defective pipe seam.
   • Defective pipe.
5) Welding/Fabrication Related
   • Defective pipe girth weld.
   • Defective fabrication weld.
   • Wrinkle bend or buckle.
   • Stripped threads/broken pipe/coupling failure.
6) Equipment
   • Gasket O-ring failure.
   • Control/Relief equipment malfunction.
   • Seal/pump packing failure.
   • Miscellaneous.

Time Independent
7) Third Party/ Mechanical Damage:
   • Damage inflicted by first, second, or third parties (instantaneous/immediate failure).
   • Previously damaged pipe (delayed failure mode).
   • Vandalism.
8) Incorrect Operations
   • Incorrect operational procedure.
9) Weather Related and Outside Force
   • Cold weather.
   • Lightning.
   • Heavy rains or floods.
   • Earth Movements.

Reference: ASME B31.8S
Pipeline Problems and Defects

Manufacturing and Construction

Material Defects
- Laminations
- Inclusions

Construction Damage
- Dents, gouges and scratches
- Buckles
Pipeline Problems and Defects

Third Party / Mechanical Damage

Dents, gouges and scratches
Pipeline Problems and Defects

Corrosion

External

Internal

Dependent on product

Can be organic (bugs/bacteria)
Cracking

Environmental

SCC

Hydrogen Induced Cracking

Stress Cracking

30 mm
Geotechnical

Land movement and slides
Pipeline Problems and Defects

Incorrect Operations

• Training of operators
• Safety systems – Pressure diaphragms, SCADA systems, etc.
Mitigation

Pipeline Design Engineering
i) Material Selection

ii) Construction procedures

iii) Route selection
Mitigation

QC and QA during manufacture and construction

i) Inspection methods employed at pipe mill

ii) NDE during all phases of construction
Mitigation

Coatings

i) External to protect from environment

ii) Internal to protect from products
Mitigation

Cathodic protection

i) Electric current to prevent electrochemical corrosion
Mitigation

Awareness to Prevent 3rd Party Damage

i) ROW signage
ii) Surveillance Systems
iii) Public notification and education
iv) One call programs

Theft, Vandalism and Terrorist Attacks
Chemical Programs - Biocides and Inhibitors

Chemicals added to the pipeline product to kill bugs or prevent internal corrosion.
Mitigation

• Operational Controls
  – SCADA Systems
  – Metering of product volumes, temperature and pressure
  – Automated valve controls
  – Surveillance systems; fiber optic
  – Leak detection
Mitigation

Pigging

The most common method for cleaning and gauging pipelines.
Operators must use a risk-based approach in prioritizing repair and mitigation activities, in which any defects or other features that have the potential to result in a near term leak or failure are addressed in a timely manner.
Risk Assessment

• Risk assessment is a process by which the probability and the consequence of an incident are quantified, and then used together to predict the risk factor for that incident.

• Simply put, Risk = Probability x Consequence.
• Thus a low probability for a high consequence incident, still has a low risk factor; *i.e. the risk of you being struck by lightening.*

• The low probability of this incident reduces the high consequence in the risk factor.
Pipeline Risk Assessment

A Matrix Grid is often used to prioritize the Risk index resulting from the Probability and Consequence. This would be used to assign priority to each item based on the resulting risk index on the grid.

![Matrix Grid Diagram]

- **5** Requires Close Monitoring
- **8** Requires Improvement
- **9** Unacceptable
- **3** Special Training Required
- **6** Requires Close Monitoring
- **7** Requires Improvement
- **1** Special Training Required
- **2** Requires Close Monitoring
- **4** Requires Close Monitoring
**API 570** - Piping Inspection Code: *Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems*

1) Pigging with Inline Inspection (ILI) Tools
2) Pressure Testing
3) Indirect Inspections – ECDA, SCCDA, ICDA
1. **In-Line Inspection Surveys**
   - Corrosion, Cracks & Deformation
     - *After the defect parameters reach ILI detection / sizing thresholds.*

2. **Hydrotest / re-test**
   - Potential to make defects worse, environmental, Line must be out of service

3. **Indirect Inspection Techniques**
   - **Cathodic Protection Surveys**
     - Annual Adjujustive & Close Interval
   - **Coating Surveys**
     - AC Attenuation & Voltage Gradient
   - **Leak Detection Surveys**
   - **GIS and DOC Mapping Surveys**
Pipeline Integrity Overview

1) ILI Surveys
   a) Cleaning
   b) Gauging
   c) Inline Inspection:
      • metal loss,
      • cracks,
      • geometric anomalies,
      • mill Defects, and
      • spatial data.
Damage on pipe must exceed the threshold for detection and the threshold for sizing before it is reported, and growth must also exceed the tolerances on successive inspections.
ILI Survey Example

What about growth?

<15% wall loss

2002

<10% wall loss

<20% wall loss

2004

30% Wall Loss

<20% wall loss

<15% wall loss

Passes Failure

Pressure Analysis
External corrosion pitting reduced the pipe wall until it could no longer hold the internal pressure of the pipe and a rupture occurred.

*Photo taken from metallurgical lab*
Post Accident Analysis

- Correlation of ILI to corrosion at failure:
  - 25%+ growth in 12 months in active areas
  - 0% growth at inactive adjacent areas
- No CIS or Coating surveys were done
ILI Standards

- API 1163 - In-Line Inspection Systems Qualification Standard
- NACE RP 0102 - Standard Recommended Practice, In-Line Inspections of Pipelines
- ASNT ILI PQ - In-Line Inspection Personnel Qualification & Certification
- Specification and Requirements for Intelligent Pig Inspection of Pipelines”, version 3.2, January, 2005, European Pipeline Operator Forum
- CSA Z662
Pressure Testing

- Usually requires removing the pipeline from service for oil and gas pipelines by displacing the product with water.
- Disposal of water used in hydrocarbon pipelines has become a serious environmental issue; expensive and difficult to complete.
Pressure testing of an existing pipeline is a possible way to demonstrate or revalidate its serviceability. Retesting an existing pipeline is not necessarily the best means to achieve confidence in its serviceability, consider:

- **The pipeline is taken out of service** & purged of product.
  - downtime represents a loss of revenue & disruption to shippers and receivers.

- Requires **large volumes of test water**.
  - 30 miles of 16” pipe requires 40,000 bbl of water =100’x100’ pond, 22’ deep!

- Used test water is considered a **hazardous material** after being contaminated with product residue.

- Test breaks **releases contaminated water** to environment.

- **Pressure reversals** may also result from pressure testing;
  - defect extensions from the test pressure decrease the remaining pressure holding capacity and remaining life of defects.
“The most important reason that a hydrostatic retest may not be the best way to validate the integrity of an existing pipeline is that in-line inspection is often a better alternative. From the standpoint of corrosion-caused metal loss, this is most certainly the case. Even with the standard resolution tools that first emerged in the late 1960s and 1970s, this was true.”

– John Keifner
Pressure Reversals

Pipeline Research Committee, American Gas Association, NG-18 Report No. 111 (Nov. 3, 1980) documents experiments used to create and demonstrate pressure reversals.

Pressure reversals occur when a defect extension occurs during a pressure test, resulting in the defect having a lower pressure holding capacity as a consequence of the test.
Example of Pressure Reversal

- Six flaws were machined into a single piece of 36” OD by 0.390” WT X-60 pipe. Each flaw had the same length, but a different depth giving a graduation in severities.
- When the single specimen containing all six flaws was pressurized to failure, the deepest flaw (No. 1) failed.
- The tips of Flaw 2, 3, and 4 exhibit some crack extension as a result of the pressurization to failure.
- Due to its extension during the test, Flaw No. 2 is now deeper than Flaw No. 1 was at the outset.

Similar specimens designed in a manner to allow subsequent pressurizations, failed during subsequent tests to the same pressure or lower!

- From Oil & Gas Journal, July 2000 article by John Keifner
**Flaw growth in 4.4 in. long part-through flaws**

Defect No. 1: Failure (leak)  
(L x d, 4.4 x 0.195 in.)

Defect No. 2: 97% of failure stress level  
(4.4 x 0.171 in.)

Defect No. 3: 94% of failure stress level  
(4.4 x 0.142 in.)

Defect No. 4: 91% of failure stress level  
(4.4 x 0.125 in.)

Defect No. 5: 89% of failure stress level  
(4.4 x 0.101 in.)

Defect No. 6: 87% of failure stress level  
(4.4 x 0.078 in.)

Note: Loading consisted of:  
1st cycle - 0  1,330 psig with 30-sec hold.  
2nd cycle - 0  1,300 psig with 30-sec hold.  
3rd cycle - 0  1,230 psig with 30-sec hold.

*In 36 in. OD x 0.390 in. WT X-60 pipe.*
Hydro-retest

A mill origin “Hook Crack” that grew to a depth of 80% from an initial depth of ~45%.

*Rust in the crack through the stage 1 and 2 region indicates water in the pipe at time of crack growth.*
Called Direct Assessment (DA) by industry, utilizes Indirect Inspection Techniques (IIT).

- Can inspect corrosion prevention systems on buried pipelines, and also internal corrosion:
  - Protective Coatings and
  - Cathodic Protection
  - Flow modelling

- Non-intrusive; non-injurious to pipeline and non-disruptive to operations.

Historically thought to be unreliable.
Prior to 2002 pipeline inspections largely consisted of Hydro Testing and ILI.

Following the Pipeline Improvement Act of 2002 there were numerous innovations emerging that would later form the foundation for a third inspection technique: Direct Assessment (DA).

The first of the DA standards to evolve was External Corrosion Direct Assessment (ECDA): NACE SP0502-2002.
The Evolution of Indirect Inspection Techniques

Indirect Inspections and the related standards have been evolving over the past century:

- 1910 Electromagnetic Pipeline Locator
- 1915 Soil Resistivity (Wenner 4 Pin)
- **1930 CP applied to pipeline for the first time**
- 1933 -850 mV criterion for CP in soils by Robert J. Kuhn.
- 1933 CP CIPS
- 1941 ACVG – Alternating Current Voltage Gradient, *AKA Pearson Survey*
- 1957 Leak Detection (flame ionization)
- 1964 DOC – Depth of cover – (EM Locator)
- **1969 NACE SP0169 published**
- 1983 DCVG – Direct Current voltage Gradient
- 1985 ACCA – Alternating Current Current Attenuation
- 1990 DGPS – Differential Global Positioning System
- 1995 ACVG Enhancement (A-Frame with 4/8Hz direction arrows)

**2000 Spectrum XLI Development Begins**

- **2002 – NACE SP0502 ECDA**
- 2004 – NACE SP0204 SCC-DA (Stress Corrosion Cracking Direct Assessment)
- 2006 – NACE SP0206 DG-ICDA (Dry Gas Internal Corrosion Direct Assessment)
- 2008 – NACE SP0208 LP-ICDA (Liquid Petroleum Internal Corrosion Direct Assessment)
- 2010 – NACE SP0110 WG-ICDA (Wet Gas Internal Corrosion Direct Assessment)

**2015 Spectrum XLI Evolution Integrates all ECDA IIT**
ECDA inspection involves a four step process:

• Pre-assessment
• Indirect Inspection
• Direct Assessment
• Post Assessment

The “Indirect Inspection” step involves use of *indirect inspection techniques* such as Cathodic Protection Close Interval Potential Survey (CP CIPS), and Direct Current Voltage Gradient (DCVG).
Regulators require records, or logs to validate inspections on pipelines:

- Hydro-retests requires pressure chart

- ILI requires inspection log

What About ECDA IIT?
Legacy IIT vs. XLI

Legacy
• Location of data readings are unreliable
• Position over pipe cannot be confirmed – locator separate from survey
• Measurements were logged manually in unsecure files
• Most measurements were analyzed subjectively by surveyor

Spectrum XLI
• Location recorded continuously via GPS & inertial mapping unit
• Pipe locator integrated into survey system
• Measurements are logged into secure encrypted raw log file
• Measurements are objectively assessed through PC software
2nd Generation XLI Survey Controller

- **GPS** + Optional:
  - Inertial DRM
  - Laser Range Finder

- Integrated digital camera + GIS right of way inventory index system

- **Locator** (DOC & AC current)
  - Optional Tilt Sensor w/ digital compass

- 4 discrete **voltage channels** are logged:
  - DC PSP = CP CIPS
  - AC PSP = filtered 50/60Hz AC induction
  - DCVG = cell to cell DC voltage gradient
  - ACVG = cell to cell AC voltage gradient

- Optional **Gas Leak Detector** – logs 1 PPM to 100% methane in air

- Optional **SONAR** – Depth of Water
XLI Survey Configurations

- GPS/GNSS
- GIS Mapping
- Depth of Cover
- Gas Leak Detection
- CP CIPS
- Coating Survey
- Water Crossing
Pipe to Soil Potentials

Voltage Gradients

Positive Perpendicular
Anomoly Density

Legacy Indirect Coating Inspection Techniques do not record continuous inspection data for the entire length of line being inspected. *Only anomalies that the equipment operator identifies and subjectively assesses to be reportable are documented.* These legacy inspections utilizing legacy equipment were themselves subjective.

- Adding **subjective** assessments to **indirect inspections** culminated in survey results that were not always reliable or repeatable.
Legacy, or Mulvany DCVG requires surveyor to identify anomalies by assessing needle movement on an analog meter:

- very subjective
- No way to audit results
- Tedious to document anomalies
Spectrum XLI records a continuous raw log of the entire survey:

- GPS and inertial mapping units stream the position, direction and velocity of the inspector to an encrypted file once per second.
- A pipeline locator streams distance and angle of the pipeline seven times per second.
- The digital volt meters for the CP CIPS and DCVG stream data 35 times per second.
Anomaly Density

The Spectrum XLI raw log enables post survey *objective analysis*.

- Every measurement is recorded in a secure *encrypted data file* that can be reviewed, analyzed and audited post survey for quality assurance.
- Not only are the critical measurements recorded, but the continuous data stream with all related telemetry data is also recorded.
XLI Digital DCVG with continuous digital waveform recorded
DCVG Raw Log

XLI Digital DCVG continuous digital waveform recorded for post survey analysis = same resolution as analog meter is recorded.

DCVG = voltage difference between On and Instant Off

DCVG = \(220\text{mV} + (0-185\text{mV}) = +35\text{mV}\)
Positive DCVG = Current Toward Negative Probe

Switching spike (common at coating faults)
Only DCVG Anomalies where surveyor’s reported based on subjective assessment
Continuous DCVG log allows post survey objective assessment = More Anomalies, and more definition of inspection data
Spectrum XLI Advanced Integrated ECDA = CP CIPS, DCVG, ACVG, ACCA, DOC, & Depth of Cover with Elevation profile
XLI Validation

Comparative surveys with legacy equipment.
Legacy DCVG vs. XLI

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