CANADA'S OIL & NATURAL GAS PRODUCERS

Best Management Practice

Mitigation of External Corrosion on Buried Carbon Steel Pipeline Systems

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The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from crude oil and natural gas production of about $110 billion a year. CAPP's mission, on behalf of the Canadian upstream crude oil and natural gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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1 Overview

External corrosion is a main contributing factor to pipeline failures and leaks. To address this issue, the CAPP Pipeline Technical Committee has developed an industry best management practice to improve the mechanical integrity of upstream pipelines. This document intends to assist upstream oil and natural gas producers in recognizing the conditions that contribute to external pipeline corrosion and identifying measures to reduce the likelihood of external corrosion incidents.

Specifically, this document addresses the design, maintenance and operating considerations for mitigating external corrosion on buried pipelines constructed with carbon steel materials. It does not address failures due to environmental cracking such as stress corrosion cracking and hydrogen-induced cracking.

This document complements CSA Z662 (Oil and Gas Pipeline Systems), the governing standard for pipeline systems in Canada, and other regulations, codes and standards. It is intended as a guide for upstream operators to address external corrosion as part of their focus on performance improvement through companies' pipeline integrity management programs. In the case of any inconsistencies between the guidance provided in this document and CSA Z662 or regulatory requirements, the latter should be adhered to.

This document is intended for use by corrosion specialists involved in the development and execution of corrosion mitigation programs, engineering teams involved in the design of gathering systems, and operations personnel involved in the implementation of corrosion mitigation programs and operation of wells and pipelines. While it contains a consolidation of key industry experience and knowledge used to reduce external corrosion, it is not intended to be a comprehensive overview of all practices.
This document applies nationally in jurisdictions where CAPP members operate. Alberta's pipeline system, the most extensive and diverse in Canada, is used as an illustrative example only.

Additional corrosion mitigation best management practices:

- Mitigation of Internal Corrosion in Sweet Gas Pipeline Systems
- Mitigation of Internal Corrosion in Sour Gas Pipeline Systems
- Mitigation of Internal Corrosion in Oil Effluent Pipeline Systems
- Mitigation of Internal Corrosion in Oilfield Water Pipeline Systems

Leak detection is addressed in a separate best management practice called Pipeline Leak Detection Programs.

These documents are available free of charge on CAPP's website at www.capp.ca.

2 Pipeline performance

The current pipeline inventory in Canada is approximately 825,000 km, consisting of about 250,000 km of gathering lines (four to 12 inches), 25,000 km of feeder lines, 100,000 km of large diameter transmission lines (four to 48 inches) and 450,000 km of local distribution lines (one-half to six inches), according to Natural Resources Canada. Much of this pipeline inventory – about 426,000 km – is located in Alberta and is regulated by the Alberta Energy Regulator (AER).

Data from the AER serves as an illustrative example for how pipeline performance has continuously improved: over the past 10 years, the length of pipelines in Alberta grew by 11 per cent while the number of pipeline incidents dropped by 48 per cent, driving the pipeline failure rate to 0.98 incidents per 1,000 km of pipeline in 2017 compared to 2.08 incidents in 2008. This decrease is due to improved requirements, industry education, improvements to inspection programs and a greater focus on pipeline safety within industry.

Nonetheless, operators recognize that pipeline performance must continue improving. This includes focus on external corrosion, which is consistently ranked among the top 3 failure types, as part of industry's effort to reduce the potential for pipeline releases and mitigating releases.

Current pipeline performance data can be viewed on the websites of most regulators in Canada.

3 Applicable standards

This section provides a summary of the most relevant standards that address external corrosion. Note that this best management practice references the standards that were current at the time of writing (June 2018). Please refer to the most recent edition of these standards as they become available.

CSA Z662: Governing standard for pipeline design, construction, operation and maintenance in all Canadian Jurisdictions.

CSA Z245.30: Governing standard that covers the qualification, inspection, testing, handling and storage of materials required for coatings applied externally to steel piping the field or a shop.

NACE RP0303: Standard for the most current technology and industry practices for the use of field-applied heat-shrinkable sleeve systems.

NACE SP0169: Standard for achieving effective control of external corrosion on buried or submerged metallic piping systems or other buried metallic structures.

NACE SP0109: Standard for field-applied bonded tape coatings.

NACE RP0105: Standard for use of liquid epoxy coatings for weld joints.

NACE RP0375: Standard for use of wax coating systems for underground pipelines.

NACE SP0502: Pipeline external corrosion direct assessment methodology.

4 Corrosion mechanisms and mitigation

Corrosion of underground structures such as pipelines is controlled by the use of protective coatings and maintaining adequate levels of cathodic protection (CP). Coating acts as a physical and dielectric (low- or non-conductive) barrier. The protective coating acts as the primary or first line of defense against corrosion. However, no coating system is perfect. To protect the pipe against corrosion at coating voids, or breaks referred to as holidays, cathodic protection current is applied. Effective cathodic protection can reduce the soil-side corrosion rate to a negligible level.

4.1 Localized and general corrosion

External corrosion of pipelines typically occurs where coating defects allow contact of steel with wet soil. Common features of this mechanism:

- Coating defects such as holidays, wrinkling or disbanding
- Moisture from the soil is in contact with the metal surface
- Cathodic protection is shielded or not sufficient

External corrosion of underground structures manifests itself as general wall loss or localized corrosion. Industry experience has shown that underground corrosion rates on bare unprotected pipe (i.e., no coating or CP) vary depending on a number of factors including soil resistivity. Although the corrosion rates may vary, it is generally accepted that all soils are corrosive.

External corrosion damage, which may start as localized pitting, can interact to an extent that the load-bearing capability of the pipeline is decreased and a failure may result.

Holiday: Break in the coating system that exposes the bare metal to the environment.

Disbondment: Failure of the bond between the coating and the steel pipe, which could allow moisture to accumulate and/or migrate under the coating.

Shielding: Prevention or diversion of cathodic protection current from its intended path. There must be a continuous electrolytic path between the protected pipe and the anodes. Disbonded coating may create a holiday as well as shield the cathodic protection current.

4.2 Soil types

Soil pH, salinity, moisture content, resistivity and microbes all affect corrosivity where bare steel is exposed.

The soil resistivity at different areas on a pipeline will vary based on moisture content and mineral composition. Table 1 summarizes the corrosivity of different types of soil for bare steel with no cathodic protection.

Table 1: Soil type, resistivity effect and corrosivity

Soil Resistivity (ohm-cm)	Soil Type	Moisture	Corrosivity
<500	Muskeg/sloughs/free water accumulations	Always wet	Very corrosive
500 - 2000	Loams/clays	Mainly wet	Corrosive to moderately corrosive
2000 - 10000	Gravels, sandy	Mainly dry	Mildly corrosive
>10000	Arid, sandy	Always dry	Non-corrosive

Source: Modified from Corrosion Basics—An Introduction, NACE Press

4.3 Protective coatings

Coatings perform two distinct functions:

- Provide a physical corrosion barrier between the steel structure and the surrounding environment
- Reduce the amount of cathodic protection current required by lowering the amount of metal which directly contacts the soil

Coating technology has changed over time, which has resulted in the use of different types of coating systems, including but not limited to:

1. Fusion Bond Epoxy (FBE)
    - Epoxy coating consisting of resins, curing agents, catalysts, accelerators, etc.
    - Excellent adhesion and resistance to soil stress, gouging and abrasion. Does not shield cathodic protection current (i.e., fails safe)

2. Abrasion Resistant Fusion Bond Epoxy (Dual Power – DPS)
    - Several layers of FBE, or FBE overcoated with a liquid epoxy, to provide improved abrasion resistance
    - Often used for horizontal bored crossing sections

3. Three (3) Layer Extruded Polyethylene (e.g., YJ2K)
    - Product consists of three layers: an FBE primer, a co-polymeric adhesive and a extruded polyethylene outer sheath

4. Two (2) Layer Extruded Polyethylene (e.g., YJ1, Yellow Jacket)
    - Rubber-modified asphalt adhesive covered by an extruded polyethylene outer sheath

5. Thermally insulated pipeline coatings such as:
    - Polyurethane foam applied direct to pipe, polyethylene tape or extruded polyethylene outer sheath currently used only in select system with built-in leak detection and monitoring systems (LDMS).
    - Primer, polyethylene tape anti-corrosion barrier, polyurethane foam, extruded polyethylene outer jacket
    - Primer, polyethylene tape anti-corrosion barrier, polyurethane foam, polyethylene tape outer jacket (no longer implemented)
    - Two layer extruded polyethylene anti-corrosion barrier, polyurethane foam, extruded polyethylene outer jacket (no longer implemented)
    - Fusion bond epoxy anti-corrosion barrier, polyurethane foam, extruded polyethylene outer jacket
    - Three layer extruded polyethylene anti-corrosion barrier, polyurethane foam, extruded polyethylene outer jacket

6. Polyethylene tape (solid film backing)
    - Primer, butyl rubber or similar adhesive, and polyethylene solid film backing applied in a spiral wrap
    - Poor adhesion, soil stress resistance. Low operating temperature.

7. Coal-tar enamel and asphalt mastics
    - 1950s/60s technology no longer in use. Coal tar pipe coatings can contain kraft paper layers, asbestos, or fiberglass layers to improve their performance
    - Care must be taken when working with coal tar coatings to avoid asbestos hazards

4.3.1 Thermally insulated pipelines

Coating systems, which also provide thermal insulation, are widely used on upstream pipelines that transport wet gas and hot bitumen. The thermal insulation helps prevent hydrates and other blockages from forming. Thermally insulated pipe systems may include an anti-corrosion barrier on the pipe (polyethylene tape or FBE applied directly to the steel surface), a layer of polyurethane foam and a polyethylene outer jacket coating.

The outer jacket coating is to prevent water ingress into the insulation and to provide mechanical protection to the insulation. The outer jacket can, for a number of reasons, be damaged and not be completely effective. Therefore, it cannot be relied on to protect uncoated steel. If water does reach the pipe surface, the anti-corrosion barrier is meant to prevent corrosion. In the past, some thermally insulated pipelines were installed without an anti-corrosion barrier. Due to serious problems with external corrosion, the current recommended industry practice is to consider the use of an anti-corrosion barrier coating. Alternatively, or in addition, water detection wires imbedded in the foam can be used to identify jacket breaches so that repairs can be completed.

At the field joints, the insulation system should involve the use of field-moulding for girth weld insulation, such as a portable mould. The moulded insulation fills the girth-weld insulation cavity better than half-shells and adds an additional moisture seal. The field moulding process is highly recommended and leads to a much lower risk of external corrosion.

For insulated pipelines, cathodic protection is believed to be of limited benefit. This is due to the multiple layers of dielectric material that tend to shield the protective current. Insulated pipelines rely solely on the integrity of the external outer jacket coating, the anti-corrosion barrier (if applied) and water detection wires (if used) to prevent external corrosion.

4.3.2 Field-applied protective coatings

It is important to ensure that the joint coating material is compatible with the plant-applied pipe coating material. An industry recommended practice is to select joint coating that closely matches the performance characteristics of the plant-applied protective coating.

Field joint and shop applied coatings are specified in CSA Z245.30 in the following groups:

- Liquid-applied epoxy or fusion bond epoxy (FBE) with a glass transition temperature of up to 115 °C
- Liquid-applied epoxy or FBE with a glass transition temperature of 115 °C or greater
- Liquid-applied epoxy or FBE intended for abrasion service
- Adhesive and a polymeric backing (e.g., tape, heat shrinkable sleeve)
- Epoxy primer, adhesive, and a polymeric backing (e.g., tape, heat shrinkable sleeve
- Anti-corrosion coating, polyurethane foam insulation, and a polymeric backing with or without adhesive (e.g., tape, heat shrinkable sleeve)
- Fibre-reinforced petrolatum, paraffin-filled, or visco-elastic systems

Common field joint or shop-applied coating systems for upstream gathering system pipelines are liquid applied epoxys, heat shrink sleeves and tapes, any of which are sometimes used in conjunction with polyurethane foam insulation (as discussed in the previous section).

Hand-applied two-part liquid epoxies are typically used for fusion bond epoxy pipelines as their performance characteristics closely match the FBE material.

Heat shrink sleeves applied in the field to pipeline girth welds are two- or three-layer systems, depending on what type of plant-applied coating is used. If the pipe is coated with a two-layer extruded polyethylene system, the sleeve will typically be a two-layer sleeve. Wrap-around style sleeves are superior in performance. The use of older tube style sleeves is not recommended as they tend to get contaminated before they can be shrunk.

Polyethylene tapes can be applied by hand-wrapping, or by using portable hand wrapping equipment. The key to successful application relies on tape selection, surface preparation and proper application. Soil stresses tend to damage tapes especially on large-diameter pipelines.

Woven Geotextile tapes are also available. These are similar to polyethylene tape but with superior soil stress resistance. These generally require the use of a hand wrapping machines.

Irregular shapes are often encountered on pipelines. These include shop bends, 45 degree elbows, 90 degree elbows, tees, flanges, weld-o-lets and repair sleeves. Shrink sleeves or tape coatings are not designed to coat such irregular shapes and have led to corrosion problems in service. Irregular shapes should be coated with Petrolatum, visco-elastic tapes or other conformable coatings specifically meant for the task. Liquid epoxy may also be used for the same purpose.

4.3.3 Installation quality for field applied coatings

Field-applied coatings used for coating weld joints, fittings, risers, or for making repairs to damaged coatings, are an important part of any coating system. CSA Z245.30 specifies the requirements for the qualification, application and inspection of field or shop-applied coatings.

The field application of pipeline coatings is always challenging. These coatings are applied outside in non-ideal weather conditions and difficult terrain. However, if the quality of the work is not comparable to the plant-applied coating, corrosion problems, often referred to as joint corrosion, will result.

Common barriers to obtaining quality-field applied coatings are lack of worker supervision, poor training of workers applying the coatings and lack of proper coating inspection. Addressing these issues will improve the long-term performance of any coating system and help avoid disbonded and shielding joint coatings.

4.3.4 Coating degradation – heat damage, disbondment and blistering

Excessive heat can cause pipe coatings to soften, flow, or become cracked and brittle, resulting in disbonded and ineffective coating.

Soil stresses to backfill weight, soil-induced shear stress applied to the coating due to thermal expansion, pipe settlement or soil settlement/soil movement can cause disbondment or wrinkling of the coating.

Excessive CP current can also cause blisters (in particular in FBE coating), especially in hot and wet soil environments. The locally increased pH and/or hydrogen molecules being liberated at a holiday in the coating may cause the coating to disbond around a holiday.

4.3.5 Coating degradation – UV damage

Cracking or embrittlement of coatings can occur due to prolonged ultraviolet exposure prior to burial. This can happen if coated pipe is stored outside for long periods. Ultraviolet exposure of fusion bond epoxy coatings may result in chalking and should be evaluated with the manufacturer prior to use. This can also occur at locations where the pipe coating comes above-ground but it not protected from the elements.

4.3.6 Shielding of cathodic protection current

The shielding of cathodic protection current is a common problem that can lead to external corrosion damage and pipeline failures. Coatings with high dielectric strength such as extruded polyethylene, shrink sleeves and polyethylene tape may lead to the shielding of cathodic protection current if damaged or disbonded.

Improving the quality of the application work can reduce the effects of disbonded and shielding pipe coatings. Alternatively non-shielding (i.e., fail safe) coatings such as FBE can be used, especially at high consequence areas such as waterways, populated areas and environmentally sensitive areas.

Most over-the-line survey techniques will not reliably detect the presence of shielding coatings. In-line inspection and repair is the best way to reduce corrosion failures if disbonded coatings and CP shielding are present.

4.4 Contributing factors

Table 2 describes the most common contributors, causes and effects of external corrosion of pipelines. It also contains corresponding industry accepted mitigation methods to reduce external corrosion.

Table 2: Contributing factors and mitigation of external corrosion

Contributor	Cause/Source	Effect	Mitigation
Excess operating temperature	• Coating failure • Coating disbondment	• Water ingress • cathodic shielding	• Maintain operating temperature below limit of coating system • Select coating system with temperature greater than operating temperature
Pipe movement/soil stress	• Excess operating temperature • Operating temperature variation • Improper support	• Coating damage • Water ingress • cathodic shielding	• Proper pipeline design • Coating selection that meets the design requirements
Ground movement/soil stress	• Unstable soils • Freeze/thaw cycles	• Coating damage • Water ingress • cathodic shielding	• Route selection • Soil stabilization • Coating selection
Improper handling and backfill	• Rock damage	• Coating damage • Water ingress • cathodic shielding	• Proper construction practices • Coating selection
Poor joint coating	• Poor joint coating selection / Incompatible pipe and joint coating • Improper application of joint coating due to inadequate training/supervision/inspection	• disbonded coating • water ingress • cathodic shielding	• Proper design and engineering • Application standards or specifications • Trained personnel • Construction QC • Coatings inspection
Improper insulation	• pipelines without a corrosion barrier between pipe and insulation • Poor joint coating quality that allows water ingress	• water can enter at holidays and follow the pipe wall • water can enter joint area • outer coating and insulation will shield cathodic protection	• Ensure coating system includes anti-corrosion barrier • Follow written coating standards or specification to ensure quality work done on joint coatings • Inject moulded foam at joint rather than half shells • Employ qualified coating inspectors to ensure quality of work

Contributor	Cause/Source	Effect	Mitigation
Concrete weights and anchor blocks	• pipelines without adequate coating within the concrete portion • damaged coating	• water ingress • Cathodic shielding by the concrete	• Coating must be designed with consideration for anchor • Coat pipe prior to pouring concrete • Inspect coating prior to installing anchor
Externally weight-coated pipe, and rock shielding	• these are not corrosion barriers	• water ingress • cathodic shielding	• Install holiday free corrosion barrier applied directly to pipe
Cased Crossings	• casing in contact with carrier pipe • damaged coating	• Cathodic shielding by casing • Insufficient cathodic protection	• Install non-metallic centralizers • Ensure coating is 100% holiday free • Keep water out of casing
Trenchless crossings – no casing	• Coating damaged during installation	• water ingress • cathodic shielding by protective coatings used as rock shields	• Install holiday free corrosion barrier • Apply cathodic protection • Use of abrasion-resistant coating
Soil-to-Air Interface (Risers)	• Damaged coating • Lack of coating	• Coating UV degradation • Coating mechanical damage • water ingress • unreliable CP due to intermittent electrolyte	• Proper coating selection • Install coating cap above interface • Inspection and maintenance • Mechanical shielding
Cathodic protection insufficiency	• cathodic protection system operating below NACE SP0169 criteria	• external corrosion at coating defects	• Perform CP system survey and adjust
Cathodic interference	• foreign cathodic protection systems • AC power lines	• Improper cathodic protection	• Properly design cathodic protection system • Proper survey and maintenance
Excess CP	• Improperly operated system	• Possible coating damage	• Perform CP system survey and adjust

5 Summary of practices for mitigating external corrosion

The following two tables summarize mandatory and recommended practices for mitigating external corrosion.

Table 3 describes practices for mitigation of external corrosion during the design and construction of a pipeline's lifecycle.

Table 4 describes the practices for the mitigation of external corrosion during the operating of a pipeline's lifecycle.

Table 3: Practices – design and construction

Element	Practice	Benefit	Comments
Coating – Plant Applied	• Select coating system with design temperature exceeding operating temperature • Coating selection should consider type of soil (water, sand, clay, rock)	• Prevent disbondment and cathodic shielding • Minimize cathodic protection current needed to prevent external corrosion	• Monitor operating conditions to prevent exceeding design specifications
Coating – Plant Applied Thermally Insulated Pipe	• Consider a coating system that includes an anti-corrosion barrier between pipe and insulation • Consider water detection wires • Protect install outer jacket coating system in rocky soils	• Prevents water ingress to pipe surface • Provides early detection of jacket breach	• Cathodic shielding may occur due to the insulation • Cannot holiday check outer coating, therefore corrosion barrier must be 100% holiday free.
Coating – Field Applied at Joints	• select a joint coating system that considers the current and future operating conditions • select a joint coating system that is compatible with the pipe body anti-corrosion coating system • select a joint coating system appropriate for the field construction environment • use proper surface preparation as recommended by the coating manufacturer • Develop coating application standards or specifications	• prevents water ingress • ensures coating system integrity	• Quality control is essential • Applicators must be trained • Applicator must be using the correct equipment and written procedures • Coating inspection to ensure quality and prevent joint corrosion

Element	Practice	Benefit	Comments
Joint type	• if joints other than butt welds (e.g., zap-lok) are used consider the effects on cathodic protection	• ensures electrical continuity necessary for CP system to function along the full length of the pipeline	• Verify by periodic system surveys
Cathodic Protection	• Install cathodic protection system	• Protects pipe against corrosion at coating holidays or damage	• Design in accordance with NACE SP0169 • Use proper electrical isolation to avoid current drainage to surface facilities and well casings
Inspection Capability	• Install or provide capability for inspection tool launching and receiving • Use consistent line diameter and wall thickness. • Use piggable valves, flanges, and fittings	• Internal inspection using intelligent pigs is the most effective method for confirming overall pipeline integrity • Proper design allows for pipeline inspection without costly modifications or downtime	• Consideration should be given to the design of bends, tees, and risers to allow for passage of inspection tools

Table 4: Practices – operating

Element	Practice	Benefit	Comments
Corrosion Assessment	• Understand what type of coatings exist in a gathering system • Evaluate operating temperature against coating system design • Assess potential for cathodic shielding • Re-assess CP system operation subsequent to a line failure or system addition	• Understand and document design and operating parameters	• Refer to CSA Z662 Clause 9 – Corrosion Control
CP system maintenance	• Perform annual survey to verify sufficient CP current • Check all insulating kits/joints • Check for interference • Check rectifiers periodically and record outputs	• Ensures reliability of CP system • Enables proof of regulatory compliance	• Regulatory requirement • Need to include deactivated, discontinued, or suspended lines • Only abandoned lines should have cathodic protection disconnected
	Note: ensure all personnel are trained and hold the required certification for the work being performed.		

Element	Practice	Benefit	Comments
Inspection Program	• Develop an inspection strategy • Utilize root cause analysis results to modify corrosion mitigation and inspection programs	• Provides assurance that the corrosion mitigation program is effective • Allows for corrosion mitigation program adjustments in response to inspection results	• Refer to Section 7 for inspection techniques • Refer to CSA Z662 Clause 9 – Corrosion Control
Repair and Rehabilitation	• Inspect to determine extent and severity of damage prior to carrying out repair or rehabilitation • Based on inspection results, use CSA Clause 10.9.2 to determine extent and type of repair required	• Prevents multiple failures on the same pipeline • Prevents recurrence of problem	• Refer to Section 8 for inspection techniques • Refer to Section 9 for repair and rehabilitation techniques • Refer to CSA Z662 Clause 10.10 for repair requirements
Failure Analysis	• Recovery of an undisturbed sample of the damaged pipeline • Conduct a thorough failure analysis • Use the results of failure analysis to re-assess CP system • Measure pipe to soil potential at failure site	• To understand corrosion mechanisms detected during inspections or as a result of a failure	• Adjust corrosion mitigation program based on results of failure analysis
Leak Detection	• Integrate a leak detection strategy	• Permits the detection of leaks	• Technique used depends on access and ground conditions
Management of Change	• Implement an effective MOC process • Maintain pipeline operation and maintenance records	• Ensures that change does not impact the integrity of the pipeline system • Understand and document design and operating parameters	• Unmanaged change may result in accelerated corrosion, using inappropriate mitigation strategy for the conditions (outside the operating range)

6 Corrosion mitigation techniques

Protective coatings have a significant impact on the lifecycle costs of a pipeline. The success of preventing external corrosion highly depends on the choice of coating and the quality of the field-applied coating work. Table 5 describes common techniques that should be considered for the mitigation of external corrosion of pipelines once a pipeline is operating.

Table 5: Corrosion mitigation techniques

Technique	Description	Comments
Cathodic Protection	• Design, install, operate, and maintain CP system in accordance with NACE SP0169and CGA OCC 1 • Ensure rectifiers are checked routinely to ensure they are operating at the target current output • Reduce unnecessary rectifier down time due to maintenance activities. • Ensure CP surveys are conducted • React quickly to isolation deficiencies, continuity bonding issues, interference and other problems to ensure CP are functioning properly • Replace depleted groundbeds in a timely fashion • Upgrade CP system if more current is needed to provide the proper levels of protection	• Regulatory requirement • CP system require regular maintenance

7 Corrosion monitoring techniques

Table 6 describes the most common techniques for monitoring corrosion and operating conditions associated with external corrosion of pipelines.

Table 6: Corrosion monitoring techniques

Technique	Description	Comments
Production Monitoring	• Ongoing monitoring of fluid temperature	• Excess temperature may damage the coating
Cathodic Protection	• Maintain, check, and operate CP system	• Refer to NACE SP0169

8 Inspection techniques

Table 7 describes common techniques that should be considered for the detection of external corrosion and coating degradation of pipelines.

Table 7: Inspection techniques

Options	Technique	Comments
CP effectiveness survey	• Close interval survey • Annual system survey	• Determines adequate protection level • Detects interference • May detect significant coating problem areas • See NACE SP0207 Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines, and NACE SP0286 Standard Practice Electrical Isolation of Cathodically Protected Pipelines • Possible alternatives outlined below
Coating Integrity Survey	• C – Scan Coating Conductance Survey • ACVG (pin to pin) and DCVG Coating survey	• Detailed coating evaluation techniques intended to identify areas of compromised coating • May employ NACE SP0502 Pipeline External Corrosion Direct Assessment Methodology and NACE TM0109 Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition • Likely does not correlate with areas of extensive external corrosion due to the fact that disbonded coating causing shielding will give erroneous results (may give false sense of security).
LDMS	• Continuous monitoring of moisture levels	• Complete investigations immediately
In-Line Inspection	• Magnetic flux leakage (MFL), ultrasonic and eddy current tools are available. MFL is the most commonly used technique	• Effective method to accurately determine location and severity of external corrosion • In-Line Inspection can find external corrosion defects • The tools are available as self-contained or tethered • Can be used for similar-service pipelines to gain better understanding of issues in an area. • The pipeline must be designed or modified to accommodate In-Line Inspection • May not be effective at risers

Options	Technique	Comments
Excavation and Integrity Digs	• Physical exposure, inspection and documenting condition of coating and the pipe.	• Often done on problem areas identified by one of the other options discussed above. • If not performed carefully in conjunction with other methods, may give false indicator of condition of the coating and pipeline.
Note: Pressure testing alone is not recommended as a method to prove long term pipeline integrity.		

9 Repair and rehabilitation techniques

Table 8 describes common techniques used for repair and rehabilitation of externally damaged pipelines. Prior to the repair or rehabilitation of a pipeline the appropriate codes and guidelines should be consulted, including:

- CSA Z662, Section 10.10 "Permanent and Temporary Repair Methods"

When evaluating localized corrosion, the user is cautioned that in addition to the assessment methods for internal pressure (hoop stress) calculations, consideration must be given to the circumferential extent of corrosion that may affect the load bearing properties where secondary stresses may be critical (e.g., bending loads, thermal stresses, soil stresses).

Table 8: Inspection techniques

Technique	Description	Comments
Coating Replacement	• Excavation, stripping or blasting and re-coating	• More suitable for localized areas of damage (e.g., joints) and areas that do not require replacement • May be possible to do without a production outage
Pipeline Section Replacement	• Remove damaged section(s) and replace with new externally coated pipe. • Joint areas should be properly coated after the new repair section is installed	• When determining the quantity of pipe to replace consider the extent of corrosion and the condition of the remaining pipeline and joint areas • Impact on pigging capabilities must be considered (use same pipe diameter and similar wall thickness) • For certain services, consideration should be given to the need for coating the inside of the pipe with a corrosion inhibitor prior to commissioning

Technique	Description	Comments
Repair Sleeves	• Reinforcement and pressure-containing sleeves may be acceptable for temporary or permanent repairs of external corrosion as per the limitations stated in CSA Z662	• For external corrosion it may be possible in some circumstances for the damaged section to remain in the pipeline as per the requirements in CSA Z662 Clause 10 • Different repair sleeves are available including composite, weld-on and bolt-on types. The sleeves must meet the requirements of CSA Z662 Clause 10 • Note: See above comments on considerations for secondary stresses when evaluating the use of different types of repair sleeves
Pipeline Replacement	• In situations where it may be difficult or uneconomic to prevent continued external corrosion damage (e.g., insulated pipelines, badly disbonded coatings, damage at joints), replacement of the pipeline may be the best option	• See Section 5 on recommended practices for design and construction

10 Additional resources

For more information on external corrosion of pipelines, pipeline coatings and cathodic protection the reader should refer to the following organizations:

- NACE International: http://www.nace.org/
- European Federation of Corrosion (EFC): http://www.efcweb.org/
- The American Society of Mechanical Engineers (ASME): http://www.asme.org/catalog/