CANADA'S OIL & NATURAL GAS PRODUCERS

Best Management Practice

Mitigation of Internal Corrosion in Carbon Steel Gas Pipeline Systems

September/2018

2018-0040

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

Internal corrosion is a main contributing factor to pipeline failures and leaks. To deal with this issue, the CAPP Pipeline Technical Committee has developed industry recommended practices to improve and maintain the mechanical integrity of upstream pipelines. They are intended to assist upstream oil and gas producers in recognizing the conditions that contribute to pipeline corrosion incidents, and identify effective measures that can be taken to reduce the likelihood of corrosion incidents.

This document addresses design, maintenance and operating considerations for the mitigation of internal corrosion in gas pipeline systems constructed with carbon steel materials.

This document does not address failures due to environmental cracking such as sulphide stress cracking (SSC) and hydrogen induced cracking (HIC). This document also does not address gas gathering systems fabricated with aluminum and non-metallic materials.

This document is complementary to CSA Z662 (Oil and Gas Pipeline Systems) and supports the development of corrosion control practices within pipeline integrity management programs, as required by CSA Z662 and the applicable regulatory agency. In the case of any inconsistencies between the guidance provided in this document and either CSA Z662 or regulatory requirements, the latter should be adhered to.

This document is intended for use by corrosion professionals involved with the development and execution of corrosion mitigation programs, engineering teams involved in the design of gathering systems, and operations personnel involved with the implementation of corrosion mitigation programs and operation of wells and pipelines in a safe and efficient manner. It contains a consolidation of key industry experience and knowledge used to reduce internal corrosion. However, 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 Oil Effluent Pipeline Systems
- Mitigation of Internal Corrosion in Oilfield Water Pipeline Systems
- Mitigation of External Corrosion on Buried 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 the CAPP 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 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 internal corrosion, ranked as the top failure type, 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 Corrosion mechanisms and mitigation

3.1 Pitting corrosion

Pitting corrosion, along the bottom of the pipeline or at the water-gas interface, is the primary corrosion mechanism leading to failures in gas pipelines. The common features of this mechanism are:

- Presence of water containing any of the following: H_2S, CO_2, bacteria, O_2, elemental sulphur, or solids.
- Pipelines carrying higher levels of free-water production with no means of water removal (i.e., no well site separation or dehydration).
- Presence of fluid traps (i.e., low spots) where water and solids can accumulate due to low gas velocity.

Localized breakdown of scales usually results in pitting corrosion attack. In wet gas gathering systems containing H_2S and CO_2 the initiation and growth of pitting corrosion can be influenced by the following variables:

- Protective scales in the absence of scale disrupters such as solids, chlorides, methanol, sulphur, high velocities, etc.
- Formation of semi-protective iron sulphide(s) scales in sour systems.

3.2 Top-of-the-line corrosion (also known as vapor-phase corrosion)

Top-of-the-line corrosion is a less common mechanism that has also led to failures. High rates of methanol injection and pipelines at elevated temperature where vapor can condense have been known contributors to top-of-the-line corrosion in both sweet and sour systems.

Tables 1 and 2 describe the most common contributors, causes and effects of internal corrosion in gas pipelines. The tables also contain corresponding industry mitigative measures used to reduce corrosion in gas pipelines.

3.3 Sulphide stress cracking

This document does not specifically address failures due to environmental cracking mechanisms such as sulphide stress cracking (SSC) or other forms of cracking such as stress corrosion cracking (SCC). Selection of materials resistant to SSC and control of combined stress are considered the primary acceptable means to prevent failures by this mechanism. Stress can result from welding, installation, soil loading, thermal expansion, operating pressure, defect, etc.

For more information on requirements to prevent SSC failures refer to:

- CSA Z662, Clause 16 Sour Service
- NACE MR 0175 / ISO 15156, Petroleum and natural gas industries – Materials for use in H_2S containing environments in oil and gas production.

3.4 Hydrogen-induced cracking

This document does not specifically address failures due to environmental cracking mechanisms related to hydrogen such as hydrogen induced cracking (HIC), hydrogen stress cracking (HSC), stepwise cracking (SWC) or stress orientated hydrogen induced cracking (SOHIC).

Where considered necessary, specification and use of materials manufactured with demonstrated HIC resistance is the preferred method for preventing failures by this mechanism. However, many of the preventative measures described in this document can help mitigate failures by this mechanism.

For more information on requirements to prevent HIC failures, refer to:

- CSA Z662, Clause 16 Sour Service
- NACE MR 0175 / ISO 15156, Petroleum and natural gas industries – Materials for use in H2S containing environments in oil and gas production
- NACE TM 0284-16, Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen Induced Cracking

4 Contributing factors to internal corrosion in gas pipeline systems

Tables 1 and 2 describe the most common contributors, causes and effects of internal corrosion in gas pipelines. The tables also contain corresponding industry accepted mitigation measures being used to reduce gas corrosion.

Table 1: Contributing factors – mechanisms

Contributor	Cause/Source	Effect	Mitigation
Hydrogen Sulphide (H_2S)	• Produced with gas from the reservoir • Can be generated by sulfate reducing bacteria • Iron sulphide scales tend to dominate when CO_2 to H_2S ratio is less than 20:1 (this limit is supplied as guidance only)	• H_2S dissolves in water to form weak acidic solution. • General corrosion rates may be slightly decreased with increasing H_2S levels • Hydrogen sulphide can form protective iron sulphide scales • Localized breakdown of iron sulphide scales results in pitting initiation	• Effective pigging and inhibition programs • Dehydration • Small amounts of H_2S (i.e., in ppm level) can be beneficial as a protective FeS film can be established
Carbon Dioxide (CO_2)	• Produced with gas from the reservoir • Can be introduced as a frac medium	• CO_2 dissolves in water to form carbonic acid • Stability of protective iron sulphide scale may be decreased by an increase in CO_2 • Corrosion rates increase with increasing CO_2 and H_2S partial pressures and temperatures	• Effective pigging and inhibition programs • Dehydration
Oxygen	• Ingress from compressors or vapor recovery units (VRU) • Introduced through endless tubing (ETU) well clean-outs • Ingress during line repairs, or inspection • Injection of methanol • Frac fluids saturated with O_2	• Oxygen can accelerate corrosion at concentrations as low as 50 parts per billion • May react with hydrogen sulphide (H_2S) to form elemental sulphur • Typical organic inhibitor effectiveness can be reduced by the presence of oxygen	• Use gas blanketing and oxygen scavengers • Minimize oxygen ingress and/or inhibit the pipeline • Optimize methanol injection and/or use inhibited methanol • Frac fluid to be deaerated or O_2 scavenged
Bacteria	• Contaminated drilling and completion fluids • Contaminated production equipment • Produced fluids from the reservoir	• Acid producing and sulfate reducing bacteria can lead to localized pitting attack • Solid deposits provide an environment for growth of bacteria	• Effective pigging program • Eliminate introduction of free water into pipelines • Treat with inhibitors and biocides

Contributor	Cause/Source	Effect	Mitigation
Water Holdup	• Low gas velocity or poor pigging practices allow water to stagnate in the pipelines • Low gas pressure (e.g., <1000kpa), may not have the gas density to push water even at higher flow rates • Absence of water separation equipment leads to water wet pipelines • Deadlegs or inactive service	• Water acts as the electrolyte for the corrosion reaction • Turbulence caused by slug flow regime can accelerate the corrosion rate	• Install pigging facilities and maintain an effective pigging program • Remove water at the wellsite by separation or dehydration • Control corrosion through effective inhibition • Remove inactive deadlegs • Effectively pig lines as soon as the wells become inactive
Chlorides	• Produced with formation water • Can be the result of spent acid returns from well stimulation	• Initiates pitting by disrupting protective scales (more prevalent in sour systems) • Increases the localized pitting rate (increases initiation and acceleration) • Increases the conductivity of water • Increased chloride levels can reduce inhibitor effectiveness	• Remove water at the wellsite by separation or dehydration • Control corrosion through effective inhibition
Solids Deposition	• Includes sands, wax, asphaltenes and scales • Loose iron sulphide accumulations are commonly formed in sour systems • Can originate from drilling fluids, workover fluids and scaling waters • May include corrosion products from down hole or upstream equipment • Insufficient gas velocities or poor pigging practices	• Can contribute to under-deposit corrosion • The deposited solids can interfere with corrosion monitoring and inhibition	• Install pigging facilities and maintain an effective pigging program • Initially, use well site separators to tank and truck liquids to minimize the effects of work over and completion activities on the pipeline • Scale inhibition

<table>
<tr><th>Contributor</th><th>Cause/Source</th><th>Effect</th><th>Mitigation</th></tr>
<tr><td rowspan="2">Methanol</td><td>• Excessive quantities of injected methanol
• Use of uninhibited methanol</td><td>• Methanol injection can introduce oxygen into the system
• High quantities of methanol may reduce inhibition effectiveness
• Methanol can break down protective FeS scales
• High quantities of methanol may cause vapor space corrosion</td><td>• Avoid over-injection of methanol
• Effective pigging and inhibition
• Remove free water
• The addition of gas dehydration or line heaters can reduce or eliminate the need for methanol usage
• Use inhibited methanol</td></tr>
<tr><td colspan="3">Note:
There is no clearly defined boundary where methanol becomes a corrosion contributor. Industry experience is that continuous methanol injection should be limited to a 1:1 water/methanol ratio or the amount required for hydrate inhibition.
The inhibitor added to the methanol is designed to form a passive layer to mitigate O_2 corrosion. This inhibitor is not intended to act as film forming inhibitor and should not be expected to protect against other types of corrosion.
Methanol can contain up to 70 mg/L dissolved O_2</td></tr>
<tr><td>Polysulphides</td><td>• May be produced with formation water from sour reservoirs
• Polysulphides are water soluble molecules
• Not detected in standard water analysis</td><td>• Acidic pH is required for polysulphides to destabilize and precipitate as elemental sulfur
• The precipitated elemental sulfur can contribute to accelerated localized corrosion</td><td>• Install pigging facilities and maintain an effective pigging program
• Implement a corrosion inhibition program</td></tr>
<tr><td>Elemental Sulphur</td><td>• Produced from reservoir or formed in the system
• Formed due to the reaction of H_2S and oxygen
• Without oxygen, thermodynamic instability/solubility due to pressure and temperature change could also generate elemental Sulphur.
• Sulphur deposition is more prevalent in liquid hydrocarbon-free systems</td><td>• Sulphur deposits can initiate and contribute to accelerated corrosion
• Presence of liquid hydrocarbons tend to keep sulphur in solution
• Synergistic effects with chloride ion accelerates corrosion</td><td>• Install pigging facilities and maintain an effective pigging program
• Implement a corrosion inhibition program
• Implement sulphur solvent treatments
• Eliminate oxygen ingress</td></tr>
</table>

Contributor	Cause/Source	Effect	Mitigation
Stray Current Corrosion	• Conductive bridge forming across insulating kits • High chloride service and high electrical potential differential	• Aggressive flange face corrosion	• Move insulating kit to a vertical position • Use thicker isolating gasket or use and electrical isolating joint • Short or remove insulating kit if CP system can handle the added load or insert a resistance bond • Internally coat flange and short spool of piping with high dielectric coating, either on both sides of the flange or at least on the side that is protected with CP.

Table 2: Contributing factors – operating practices

Contributor	Cause/Source	Effect	Mitigation
Drilling and Completion Fluid	• Introduction of spent acids and kill fluids • Introduction of solids • Introduction of bacteria • Introduction of O_2 and CO_2	• Lower pH • Higher chloride concentration, which can accelerate corrosion and reduce corrosion inhibitor dispersability • Accelerated corrosion due to breakdown of the protective iron sulphide scales	• Produce well to well site separator, tankage and trucking water until drill and complete fluids and solids are recovered • Supplemental pigging and inhibition of pipelines before and after work over activities
	Note: *Produce wells to surface test facilities until drilling and completion fluids are recovered or neutralized. The pH must be 4 or greater before producing the liquids back into the pipeline unless a specific corrosion control program is applied.* *The effect of chemistry of residual stimulation fluids such as chlorides should also be considered. The existing inhibitor program may not be effective for these conditions.*		
Critical Gas Velocity	• Critical gas velocity is reached when there is insufficient flow to sweep the pipeline of water and solids	• A buildup of water and solids (elemental sulphur, iron sulphides etc.) causes corrosion • Turbulence caused by slug flow regime can accelerate the corrosion rate	• Design pipeline to exceed critical velocity • Establish operating targets based on critical gas velocity to trigger appropriate mitigation requirements (pigging, batch inhibition etc.)

Contributor	Cause/Source	Effect	Mitigation
Detrimental Operating Practices	• Ineffective pigging • Ineffective inhibition • Intermittent operation • Inadequate pipeline suspension practices • Commingling of incompatible produced fluids • Flow back of work-over fluids into the pipeline • Deadlegs due to changes in production or operation of pipelines	• Accelerated corrosion	• Design pipelines to allow for effective shut-in and isolation • Develop and implement proper suspension procedures, including pigging and inhibition • Establish acceptable operating parameters • Test for fluid incompatibilities
Management of Change (MOC)	• Change in production characteristics or operating practices • Well re-completions and workovers • Lack of system operating history and practices • Changing personnel and system ownership	• Unmanaged change may result in unexpected corrosion	• Implement an effective MOC process • Maintain integrity of pipeline operation and maintenance history and records • Re-assess corrosivity on a periodic basis

5 Recommended practices

Table 3 describes the recommended practices for mitigation of internal corrosion in the design and construction phase of gas pipelines.

Table 4 describes the recommended practices for mitigation of internal corrosion in the operating phase of gas pipelines.

Table 3: Recommended practices – design and construction

Element	Recommended Practice	Benefit	Comments
Materials of Construction	• Use normalized EW line pipe that meets the requirements of CSA Z245.1 Steel Pipe • Consider using corrosion-resistant non-metallic materials such as HDPE or composite materials as per CSA Z662, Clause 13 • Use CSA Z245.1 Sour Service Steel Pipe for sour gas pipelines, as per the requirements of CSA Z662	• Normalized EW prevents preferential corrosion of the weld zone • Non-metallic materials are corrosion resistant	• EW pipe should be installed with the seams orientated to the top half of the pipe to minimize preferential seam corrosion • Non-metallic materials may be used as a liner or a free standing pipeline depending on the service conditions. Steel risers could be susceptible to corrosion
	Note: *There are CSA and regulatory restrictions on the use of non-metallic materials (e.g., HDPE, nylon and composite materials) in sour gas service. The application of these materials is changing with industry experience and technological improvements.*		
Dehydration	• Install gas dehydration facilities • Ensure dehydration units are operating properly	• Elimination of free water from the system reduces the potential for corrosion	• Consider mitigation requirements for upset conditions
Water Removal	• Install water separation and removal	• Removal of produced water from the system reduces the potential for corrosion	• Only produced water is being removed therefore pigging and mitigation measures may still be required • Be careful of corrosion due to dew point being reached (condensed water formed may have very low pH due to insufficient buffering capacity)

Element	Recommended Practice	Benefit	Comments
Pipeline Isolation	• Install valves that allow for effective isolation of pipeline segments from the rest of the system • Install the valves as close as possible to the tie-in point • Install blinds for effective isolation of inactive segments	• Allows for more effective suspension and discontinuation of pipeline segments • Reduces the amount of lost production and flaring during maintenance activities	• Removes potential deadlegs from the gathering system • Be aware of creating deadlegs between isolation valve and mainline at tie-in locations (i.e., install 12 o'clock tee tie-ins, or above ground riser tie-ins) • Develop shut-in guidelines for the timing of required steps to isolate and lay up pipelines in each system
Deadlegs	• Design and construct system to avoid or mitigate the effect of deadlegs • Establish an inspection program for existing deadlegs	• Avoid corrosion due to stagnant conditions	• Stagnant conditions lead to accelerated corrosion • For existing deadlegs removal or routine inspection may be required
Pipeline Sizing	• Design pipeline system to maintain flow above critical velocity • For pipelines that operate below the critical velocity ensure corrosion mitigation programs are effective for the conditions	• Using smaller lines where possible increases gas velocity and reduces water holdup and solids deposition	• Design pipeline system to take into account changes in well deliverability • Consider the future costs of corrosion mitigation for oversized pipelines • Consider the impact of crossovers, line loops and flow direction changes
Pigging Capability	• Install or provide provisions for pig launching and receiving capabilities • Use consistent line diameter and wall thickness • Use piggable valves, flanges and fittings	• Pigging is one of the most effective methods of internal corrosion control • Pigging improves the effectiveness of corrosion inhibitor treatments	• Multi-disc/cup pigs have been found to be more effective than ball or sponge type pigs • Receivers and launchers can be permanent or mobile • Use pigs that are properly oversized, undamaged and not excessively worn

Element	Recommended Practice	Benefit	Comments
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 inline inspection (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 navigation of inspection devices (mandatory for some sour lines per Clause 16 in CSA Z662)

Table 4: Recommended practices – operations

Element	Recommended Practice	Benefit	Comments
Completion and Workover Practices	• Produce wells to surface test facilities until drilling and completion fluids and solids are recovered	• Removal of stimulation and workover fluids reduces the potential for corrosion	• Supplemental pigging and inhibition of pipelines may be required prior to or following workover activities
Corrosion Assessment	• Evaluate operating conditions (temperature, pressure, water quality) and prepare a corrosion mitigation program • Communicate corrosion assessment, operating parameters and the mitigation program to all key stakeholders, including field operations and maintenance personnel • Re-assess corrosivity on a periodic basis and subsequent to a line failure	• Effective corrosion management comes from understanding and documenting design and operating parameters	• Refer to CSA Z662 Clause 9 - Corrosion Control • Define acceptable operating ranges consistent with the mitigation program • Consider the effects of H_2S, CO_2, O_2, chlorides, elemental sulphur, methanol, bacteria and solids • Consider supplemental requirements for handling completion and workover fluid backflow

Element	Recommended Practice	Benefit	Comments
Corrosion Mitigation and Monitoring	• Develop and communicate the corrosion mitigation and monitoring program to all key stakeholders, including field operations and maintenance personnel • **NOTE:** Ensure personnel understand their responsibilities and are accountable for implementation and maintenance of corrosion management programs • Develop pipeline suspension and discontinuation procedures	• Allows for an effective corrosion mitigation program	• Refer to Section 6 for Corrosion Mitigation Techniques • Refer to Section 7 for Corrosion Monitoring Techniques • Refer to CSA Z662 Clause 9 – Corrosion Control • Number and location of monitoring devices depend on the predicted corrosivity of the system. • Process sampling for monitoring of Cl-, pH, Fe, Mn, bacteria and solids (monitoring of iron-manganese ratio may not be as effective in H_2S system) • Consider provisions for chemical injection, monitoring devices and sampling points • Establish shut-in guidelines for the timing of requiring steps to isolate and lay up pipelines in each system
Inspection Program	• Develop an inspection program or strategy • Involve field operations and maintenance personnel in the development of inspection strategy	• Creates greater buy-in and awareness of corrosion mitigation program • Provides assurance that the corrosion mitigation program is effective	• Refer to Section 8 for Corrosion Inspection Techniques • Refer to CSA Z662 Clause 9 – Corrosion Control • Risk assessments should be used to prioritize inspections • Adjust corrosion-mitigation program based on results
Failure Analysis	• Recover an undisturbed sample of the damaged pipeline • Conduct a thorough failure analysis • Use the results of failure analysis to reassess corrosion mitigation program	• Improved understanding of corrosion mechanisms detected during inspections or as a result of a failure • Allows for corrosion mitigation program adjustments in response to inspection results	• Adjust corrosion mitigation program based on results of failure analysis • Some onsite sampling may be required during sample removal (e.g., bacteria testing)

Element	Recommended Practice	Benefit	Comments
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 to determine extent and type of repair required • Implement or make modifications to corrosion control program after repairs and failure investigations, so that other pipelines with similar conditions are inspected and mitigation programs revised as required	• Prevents multiple failures on the same and similar pipelines • Prevents reoccurrence of problem	• Refer to Section 8 for Corrosion Inspection Techniques • Refer to Section 9 for Repair and Rehabilitation Techniques • Refer to CSA Z662 Clause 10 for repair requirements
Leak Detection	• Integrate a leak detection strategy	• Permits the detection of leaks	• Technique used depends on access and ground conditions
Management of Change (MOC)	• 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 or using inappropriate mitigation strategy for the conditions (outside the operating range)

6 Corrosion mitigation techniques

Table 5 describes common techniques that should be considered for the mitigation of internal corrosion in gas pipelines.

Table 5: Recommended practices – corrosion mitigation

Technique	Description	Comments
Pigging	• Periodic pigging of pipeline segments to remove liquids, solids and debris	• Pigging is one of the most effective methods of internal corrosion control • Can be an effective method for cleaning pipelines and reducing potential for bacteria colonization and under-deposit corrosion • Selection of pig type and sizing is important to ensure effectiveness • Requires facilities for launching and receiving pigs • Common practice to help productivity of low volume gas wells
Batch Corrosion Inhibition	• Periodic application of a batch corrosion inhibitor to provide a protective barrier on the inside of the pipe • Initial batch treatment of the pipeline is critical at pipeline commissioning, after new pipeline construction, repairs or suspension • Batching is required after any activity that will disrupt the protective films (inspection, line repairs, workovers, etc.)	• Provides a barrier between corrosive elements and the pipe surface • Some corrosion inhibitors may not be effective in top-of-the-line corrosion • Application procedure is important in determining effectiveness (i.e., volume of chemical, diluent used, contact time and application interval) • Effectiveness is reduced downstream with underground tie-ins • Should be applied between two specialty pigs to effectively clean and lay down inhibitor on the pipe • Should be used in conjunction with pigging to remove liquids and solids (i.e., the inhibitor must be applied to clean pipe to be the most effective)
	Note: *Large diameter lines may require special design and/or procedures to ensure batch slug remains intact.* *Batch programs have numerous variables (including people, chemical and application) and need to be properly managed to ensure effective implementation and performance monitoring*	

Technique	Description	Comments
Continuous Corrosion Inhibition	• Continuous injection of a corrosion inhibitor to reduce the corrosivity of the transported fluids or provide a barrier film	• Program design is important (e.g., product selection, performance criteria, production characteristics) • Can help with top-of-the-line corrosion mitigation • Corrosion inhibitor may be less effective at contacting the pipe surface in a dirty system
	Note: *Inhibition programs have numerous variables (including people, chemical and application) and need to be properly managed to ensure effective implementation and performance monitoring.*	
Biocide Chemical Treatment	• Periodic application of a biocide to kill bacteria in the pipeline system.	• Effective in killing bacteria in systems known to contain bacteria • Used in conjunction with pigging (to clean the line) will enhance effectiveness • Downhole batch application helps ongoing treatment of produced fluids flowing into the pipeline • Use of improperly selected biocides can create a foam that can be an operational issue
Oxygen Control	• Use gas blanketing and O_2 scavengers • Avoid purging test equipment into the pipeline • Optimize methanol injection and/or use inhibited methanol • Batch treat pipelines following line repairs, inspections and hydrotesting	• O_2 ingress will accelerate the corrosion potential (can also create sulfur compounds)

7 Corrosion monitoring techniques

Table 6 describes the most common techniques for monitoring corrosion and operating conditions associated with internal corrosion in gas pipelines.

Table 6: Corrosion monitoring

Technique	Description	Comments
Gas and Oil Analysis	• Ongoing monitoring of gas composition for H_2S and CO_2 content. If present, the analysis of liquid hydrocarbon properties is useful	• Acid gas content must be understood and should be periodically re-assessed • Trend of reservoir souring should be monitored
Water Analysis	• Ongoing monitoring of water for chlorides, dissolved metals, suspended solids and chemical residuals	• Changes in water chemistry will influence the corrosion potential • Trends in dissolved metals (e.g., Fe, Mn) concentration can indicate changes in corrosion activity (monitoring of iron-manganese ratio may not be as effective in H_2S system) • Chemical residuals can be used to confirm the level of application and changes in water production • Sampling location and proper procedures are critical for accurate results
Production Monitoring	• Ongoing monitoring of production conditions such as pressure, temperature and flow rates	• Changes in operating conditions will influence the corrosion potential • Production information can be used to assess corrosion susceptibility based on fluid velocity and corrosivity
Mitigation Program Compliance	• Ongoing monitoring of mitigation program implementation, execution and documentation	• Chemical pump reliability and inhibitor inventory control is critical where mitigation program includes continuous chemical injection • Corrosion mitigation program must be properly implemented and maintained to be effective • Impact of any non-compliance to the mitigation program must be evaluated to assess the effect on corrosion
Corrosion Coupons	• Used to indicate general and pitting corrosion susceptibility and mitigation program effectiveness	• Trends in coupon data can indicate changes in corrosion activity • Coupons should be used in conjunction with other monitoring and inspection techniques • Coupon type, placement and data interpretation are critical to successful application of this method

Technique	Description	Comments
Bio-spools	• Used to monitor for bacteria presence and biocide effectiveness	• Bio-spool placement and data interpretation are critical to successful application of these methods • Bio-spools should be used in conjunction with other monitoring and inspection techniques • Solids pigged out of pipelines (pig yields) can be tested for sessile bacteria levels • Bacteria presence on surfaces is considered a better way to quantify type and numbers present in the system
Electrochemical Monitoring	• There are a variety of methods available such as electrochemical noise, linear polarization, electrical resistance, hydrogen foils/probes and field signature method	• Device selection, placement and data interpretation are critical to successful application of these methods • Continuous or intermittent data collection methods are used • Electrochemical monitoring should be used in conjunction with other monitoring and inspection techniques

8 Corrosion inspection techniques

Table 7 describes common techniques that should be considered for the detection of internal corrosion in gas pipelines.

Note: Due to localized corrosion being the prevalent failure mechanism in sour gas pipelines, hydrotesting alone may not be adequate to prove pipeline integrity.

Table 7: Corrosion inspection techniques

Options	Technique	Comments
Inline Inspection	• Magnetic flux leakage (MFL), ultrasonic and eddy current tools are available. MFL is the most commonly used technique. • UT and Eddy Current tools are also available	• Effective method to accurately determine location and severity of corrosion • Inline Inspection can find internal and external corrosion defects • The tools are available as self-contained or tethered • The pipeline must be designed or modified to accommodate inline inspection • To run a tethered tool inspection it is often necessary to dig bellholes and cut the pipeline
Non-Destructive Examination (NDE)	• Ultrasonic inspection, radiography or other NDE methods can be used to measure metal loss in a localized area	• An evaluation must be done to determine potential corrosion sites prior to conducting NDE • See NACE SP0110 Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines or NACE SP0206 Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Gas • The use of multi-film radiography is an effective screening tool prior to using ultrasonic testing • NDE is commonly used to verify inline inspection results, corrosion at excavation sites and above-ground piping • Practical limitations of NDE methods and the factors affecting accuracy must be understood
Video Camera / Boroscope	• Visual inspection tool to locate internal corrosion	• Used to locate and determine the presence of corrosion damage, but it is difficult to determine severity • Technique may be limited to short inspection distances • Cannot directly measure depth of corrosion pits

Options	Technique	Comments
• Destructive Examination	• Physical cutout of sections from the pipeline	• Consideration should be given to locations where specific failure modes are most likely to occur • See NACE SP0110 Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines or NACE SP0206 Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Gas

9 Repair and rehabilitation techniques

Table 8 describes the common techniques for repair and rehabilitation of pipelines damaged by internal gas corrosion.

Prior to the repair or rehabilitation of a pipeline the appropriate codes and guidelines should be consulted, including:

- CSA Z662, Clause 10, Permanent and Temporary Repair Methods
- CSA Z662, Clause 13, Reinforced Composite, Thermoplastic lined and Polyethylene Pipelines

Table 8: Repair and rehabilitation techniques

Technique	Description	Comments
Pipe Section Replacements	• Remove damaged section(s) and replace.	• When determining the quantity of pipe to replace, consider the extent of the corrosion and the extent and severity of damage or degradation of any internal coatings or linings along with the condition of the remaining pipeline • Impact on pigging capabilities must be considered (use same pipe diameter and similar wall thickness) • Replaced pipe section should be coated with corrosion inhibitor prior to commissioning or coated with an internal coating compatible with the existing pipeline

Technique	Description	Comments
Repair Sleeves	• Reinforcement and pressure-containing sleeves may be acceptable for temporary or permanent repairs of internal corrosion as per the limitations stated in CSA Z662	• For internal 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 along with proper corrosion control practices to prevent further deterioration • Different repair sleeves are available including composite, weld-on and bolt-on types. Sleeves must meet the requirements of CSA Z662 Clause 10.
Polymer Liners	• Material selection, liner design, service conditions, and installation procedures are critical to liner performance • A polymer liner is inserted in the steel pipeline • The steel pipe must provide the pressure containment capability	• Variety of materials are available with different temperature and chemical resistance capabilities • Impact on pigging capabilities must be considered • Polymer liners may eliminate the need for internal corrosion mitigation, corrosion monitoring and inspection • Installation of liners will require review of chemical inhibition programs of any remaining bare steel components
Composite or Plastic Pipe	• Freestanding composite or plastic pipe can be plowed-in for new lines or pulled through old pipelines • This pipe must be designed to provide full pressure containment	• A variety of materials are available with different temperature and chemical resistance capabilities • Freestanding plastic or composite pipelines are limited by pressure and H_2S concentration by CSA Z662 and regulatory bodies • Impact on pigging capabilities must be considered • Composite or plastic pipelines may eliminate the need for internal corrosion mitigation, corrosion monitoring and inspection • Installation of composite or plastic pipe will require review of chemical inhibition programs of any remaining bare steel components
Pipeline Replacement	• Using internally coated steel pipeline systems with an engineered joining system should also be considered • Alteration or replacement of the pipeline allows for proper mitigation and operating practices to be implemented	• Should be pig and inspection tool compatible • Refer to Section 5 Recommended Practices in this document for details • Ensure that when replacements occur, the alteration or replacement of the pipeline allows for proper mitigation and operating practices to be implemented

10 Additional resources

For more information on pipeline corrosion, 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/