CAPP CANADA'S OIL & NATURAL GAS PRODUCERS

Best Management Practice

Mitigation of Internal Corrosion in Carbon Steel Oil Effluent 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

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 best management practices to improve and maintain the mechanical integrity of upstream pipelines. This document intends to assist upstream oil and natural gas producers in recognizing the conditions that contribute to internal pipeline corrosion and identify measures to reduce the likelihood of internal corrosion incidents.

Specifically, this document addresses design, maintenance and operating considerations for the mitigation of internal corrosion in oil effluent pipeline systems. In this document, oil effluent pipelines are defined as those constructed with carbon steel materials and transporting oil, natural gas and water for sweet and sour services. This document does not address the deterioration of aluminum and non-metallic materials. While the scope of this document does not include crude oil pipelines, many of the same principles for internal corrosion, mitigation and monitoring may apply.

This document complements CSA Z662 (Oil and Gas Pipeline Systems), the governing standard for pipeline systems in Canada, 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 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 with operation of wells and pipelines. It contains a consolidation of key industry experience and knowledge used to reduce oil effluent internal pipeline corrosion. However, it is not intended to be 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 Sour Gas Gathering Systems
- Mitigation of Internal Corrosion in Sweet Gas Gathering 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 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.

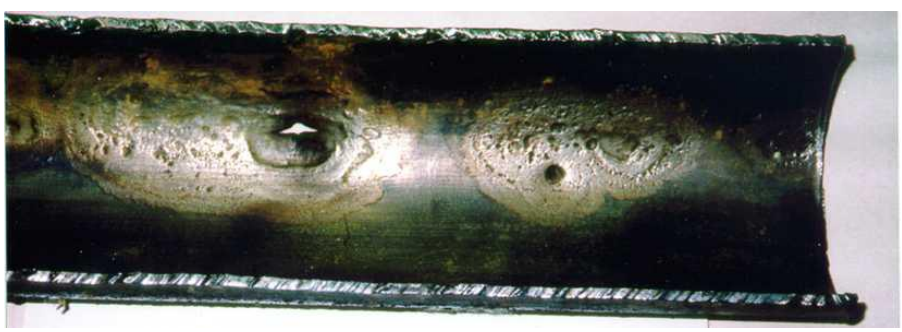
Nonetheless, operators recognize that pipeline performance must continue improving. This includes focus on internal corrosion, ranked as the top failure type, as part of industry's effort to reduce the potential for pipeline releases and mitigating releases.

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

3 Corrosion mechanisms and mitigation

Pitting corrosion along the bottom of the pipeline is the primary corrosion mechanism leading to failures in oil effluent pipelines. The common features of this mechanism are:

- Presence of water containing any of the following: CO2, H2S, chlorides, bacteria, O2, or solids
- Pipelines carrying higher levels of free-water production (high water/oil ratio or water-cut)
- Presence of liquid traps where water and solids can accumulate or are left (e.g., inactive pipelines)



Example of internal corrosion in an oil effluent pipeline.

Table 1 describes the most common contributors, causes and effects of internal corrosion in oil effluent pipelines. They also contain common mitigation measures to reduce pipeline corrosion.

They apply to internally bare carbon steel pipeline systems and coated or lined pipelines where deterioration or damage has allowed water contact with the steel substrate.

Table 1: Contributing factors and prevention of internal oil effluent corrosion - mechanisms

Contributor	Cause/Source	Effect	Mitigation
Water Holdup	• Low velocity and poor pigging practices allow water to stagnate in the pipelines • Deadlegs or inactive service	• Water acts as the electrolyte for the corrosion reaction • Chlorides increase the conductivity of water and may increase the localized pitting rate • In some cases, pitting corrosion may not occur if chloride ion concentration is very high (>10 per cent)	• Install pigging facilities and maintain an effective pigging program • Control corrosion through effective corrosion inhibition practices • Remove stagnant deadlegs • Refer to Table 3.2 • Effectively pig lines as soon as the wells become inactive
Carbon Dioxide	• Produced with gas from the reservoir • CO_2 flooding	• CO_2 dissolves in water to form carbonic acid • Corrosion rates increase with increasing CO_2 partial pressures	• Effective pigging and inhibition
Hydrogen Sulphide (H_2S)	• Produced with gas from the reservoir • Generated by sulfate reducing bacteria	• Hydrogen sulphide can form protective iron sulphide scales to reduce general corrosion rates • Localized breakdown of iron sulphide scales triggers pitting corrosion attack	• Effective pigging and inhibition programs • See 'bacteria'
Bacteria	• Contaminated drilling and completion fluids • Contaminated production equipment • Produced fluids from the reservoir (contaminated)	• Acid producing and sulfate reducing bacteria can lead to localized pitting attack • Solid deposits provide an environment for growth of bacteria	• Treat with corrosion inhibitors and biocides • Effective pigging program • Treat any introduced fresh water with biocide.
Critical Velocity	• Critical velocity is reached when there is insufficient flow to sweep the pipeline of water and solids	• Water accumulation and solids deposition (inorganic sands, mineral scales, corrosion products, elemental sulphur, etc.) accelerate corrosion	• Design pipeline to exceed critical velocity • Establish operating targets based on critical gas and liquids velocity to trigger appropriate mitigation requirements e.g. pigging, batch inhibition

Contributor	Cause/Source	Effect	Mitigation
Solids Deposition	• Mainly produced from the formation; can include wax, asphaltenes, scales and sands • May originate from drilling fluids, workover fluids and scaling waters • May include corrosion products from upstream equipment • Insufficient velocities and poor pigging practices	• Can contribute to under-deposit corrosion • Scaling can interfere with corrosion monitoring and inhibition • Solids will reduce the corrosion inhibiting efficiency	• Install pigging facilities and maintain an effective pigging program • Use well site separators to tank and truck water during work over and completion activities to minimize the effects on the pipeline • Scale suppression
Drilling and Completion Fluids	• Introduction of bacteria • Introduction of spent acids and kill fluids • Introduction of solids	• Accelerated corrosion • Lower pH • Higher chloride concentration, which can accelerate corrosion and reduce the corrosion inhibitor dispersability	• Produce wells to well site separator, tanking and trucking water until drilling and completion fluids and solids are recovered • Supplemental pigging and batch inhibition of pipelines before and after work over activities
Detrimental Operating Practices	• Ineffective pigging • Ineffective inhibition • Inadequate pipeline suspension activities • Commingling of incompatible produced fluids	• Accelerated corrosion	• Design pipelines to allow for effective shut-in and isolation • Develop and implement proper suspension procedures, including pigging and batch inhibition • Test for fluid incompatibilities
Management of Change (MOC)	• Change in production characteristics or operating practices • Well re-completions and work overs • Lack of system operating history and practices • Changing personnel and system ownership	• Unmanaged change may result in accelerated corrosion	• Implement an effective MOC process as part of the IMP • Maintain integrity of pipeline operation and maintenance history and records • Re-assess corrosivity on a periodic basis

Contributor	Cause/Source	Effect	Mitigation
Oxygen Ingress	• Completion fluids or other fluids saturated with O_2 • Tanks and other wellsite equipment (e.g. pump jack compressors) • Methanol injection	• Accelerated corrosion • Can precipitate elemental sulphur if service is sour • Corrosion inhibitors may be ineffective if O_2 is present	• Scavenge O_2 or deaerate
Stray Current Corrosion	• Conductive bridge forming across insulating kits • High chloride service and high electrode potential differential	• Aggressive flange face corrosion	• Move insulating kit to a vertical position • Use thicker isolating gasket or use an electrical isolating joint. • Short or remove insulating kit if CP system can handle the added load. • Insert a resistance bond or modify the CP system to reduce the potential differential. • 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.

4 Recommended practices

Table 2 describes the recommended practices for mitigation of internal corrosion during design and construction of oil effluent pipelines.

Table 3 describes the recommended practices for mitigation of internal corrosion during operations of oil effluent pipelines.

Table 2: Recommended practices – design and construction

Element	Recommended Practice	Benefit	Comments
Materials of Construction	• Use normalized electric resistance welding (ERW) line pipe that meets the requirements of CSA Z245.1 Steel Pipe • Use CSA Z245.1 Sour Service Steel Pipe for sour oil effluent pipelines • Consider use of corrosion resistant materials such as High Density Polyethylene (HDPE) or fiber reinforced composite materials as per CSA-Z662, Clause 13 Plastic Pipelines	• Normalized ERW prevents preferential corrosion of the weld zone • Reduces chances of sulfide stress cracking failures • Non-metallic materials are corrosion resistant	• EW seams should be placed on the top half of the pipe to minimize preferential corrosion • Non-metallic materials may be used as a liner or a free standing pipeline depending on the service conditions. Be aware that internally bare steel risers would be susceptible to corrosion.
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 in-active pipeline segments	• Allows for more effective suspension and discontinuation of pipeline segments	• Removes potential “deadlegs” from the gathering system • Be aware of creating “deadlegs” between isolation valve and mainline at tie-in locations, which can be mitigated through tee tie-ins at 12 o’clock, or above ground riser tie-ins • Develop shut-in guidelines for the timing of requiring steps to isolate and lay up pipelines in each system

Element	Recommended Practice	Benefit	Comments
Pipeline Sizing	• Design pipeline system to ideally maintain flow above critical velocity	• Using optimal line size where possible increases velocity and reduces water stagnation and solids accumulation	• Consider future operating conditions such as changes in well deliverability • Consider the future corrosion mitigation cost of oversized pipelines operating under the critical velocity • 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 can improve the effectiveness of corrosion inhibitors	• Multi-disc/cup pigs have been found to be more effective than ball or foam type pigs • Receivers and launchers can be permanent or mobile • Use pigs that are properly over sized, undamaged, and not excessively worn • Pigging may be ineffective when there are large differences in wall thickness or line sizes
Inspection Capability	• Install or provide capability for inline inspection tool launching and receiving • Use consistent line diameter and wall thickness. • Use piggable valves, flanges, and fittings	• Internal inspection using inline inspection 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 by the inspection devices

Table 3: Recommended practices – operations

Element	Recommended Practice	Benefit	Comments
Completion and Workover Practices	• Produce wells to well site separation, tanking and trucking of water until completion and workover fluids and solids are recovered	• Removal of completion and/or workover fluids reduces the potential for corrosion	• Supplemental pigging and batch inhibition of pipelines may be required before and after workover activities
Corrosion Assessment	• Evaluate operating conditions (temperature, pressure, well effluent and volumes) and prepare a corrosion mitigation program • Develop and communicate corrosion assessment, operating parameters and the mitigation program with 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 (See CSA Z662 Clause 10) • Consider the effects of oxygen, methanol, bacteria and solids • Consider supplemental requirements for handling completion and workover fluid backflow
Corrosion Inhibition and Monitoring	• Develop and communicate the corrosion inhibition and monitoring program with 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 suspension and lay up procedures for inactive pipelines	• Allows for an effective corrosion mitigation program	• Refer to Section 4 for Corrosion Mitigation Techniques • Refer to Section 5 for Corrosion Monitoring Techniques • Refer to CSA Z662 Clause 9 – Corrosion Control • Number and location of monitoring devices is dependent on the predicted corrosivity of the system • Process sampling for monitoring such as bacteria, Cl-, pH, Fe, Mn and solids • Consider provisions for chemical injection, monitoring devices and sampling points

Element	Recommended Practice	Benefit	Comments
Inspection Program	• Develop an inspection program or strategy • Communicate the inspection program to field operations and maintenance personnel	• Creates greater “buy in” and awareness of corrosion mitigation program • Provides assurance that the corrosion mitigation program is effective	• Refer to Section 7 for Corrosion Inspection Techniques • Refer to CSA Z662 Clause 9 – Corrosion Control
Failure Investigation	• Recovery of an undisturbed sample of the damaged pipeline • Conduct thorough failure analysis • Use the results of the failure analysis to reassess the 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 the corrosion mitigation program based on the results of the failure analysis • Some onsite sampling may be required during sample removal (e.g. bacteria testing, elemental sulphur, etc.)
Repair and Rehabilitation	• Inspect to determine extent and severity of damage prior to carrying out any repair or rehabilitation • Based on inspection results, use CSA Z662 Clause 10 to determine extent and type of repair required • Implement or make modifications to integrity management 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 pipeline • Prevents reoccurrence of problem in other like pipelines in the system	• Refer to Section 7 for Corrosion Inspection Techniques • Refer to Section 9 for Repair and Rehabilitation Techniques • Refer to CSA Z662 Clause 10for repair requirements
Leak Detection	• Integrate a leak detection strategy	• Permits the detection of leaks	• Technique utilized 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)

5 Corrosion mitigation techniques

Table 4 describes common techniques to be considered for the mitigation of internal corrosion in oil effluent pipelines.

Table 4: Corrosion mitigation techniques

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 of cleaning pipelines and reducing potential for bacteria colonization and under-deposit corrosion • Selection of pig type and sizing is important • Requires facilities for launching and receiving pigs
Batch Corrosion Inhibitor Chemical Treating	• Periodic application of a batch corrosion inhibitor to provide a protective barrier on the inside surface of the pipe	• Provides a barrier between corrosive elements and pipe surface • Application procedure is important in determining effectiveness (eg. volume and type of chemical, diluent used, contact time, and application interval) • Effectiveness may be reduced on existing pitting, in particular deep and narrow morphology • Should be applied between two 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)
Continuous Corrosion Inhibitor Chemical Treating	• Continuous injection of a corrosion inhibitor to reduce the corrosivity of the transported fluids or provide a barrier film	• Less common technique due to the high cost to treat high volume water producing wells • Corrosion inhibitor may be less effective at contacting full pipe surface especially in a dirty system, batch may be more effective • Chemical pump reliability is important in determining effectiveness

Technique	Description	Comments
Biocide Chemical Treating	• Periodic application of a biocide to kill bacteria in the pipeline system.	• Assists in controlling bacterial growth • Use in conjunction with pigging (to clean the line) will enhance effectiveness • Batch application typically most effective (e.g. application down-hole leads to ongoing treatment of produced fluids flowing into the pipeline) • The use of improperly selected biocides can create a foam that can be a serious operational issue

6 Corrosion monitoring techniques

Table 5 describes the most common techniques for monitoring corrosion and operating conditions associated with internal corrosion in oil effluent pipelines.

Table 5: Corrosion monitoring techniques

Technique	Description	Comments
Gas and Oil Analysis	• Ongoing monitoring of gas composition for H2S and CO2 content. The analysis of liquid hydrocarbon properties is useful.	• Acid gas content must be understood and should be periodically re-assessed
Water Analysis	• Ongoing monitoring of water for chlorides, pH dissolved metal ions, bacteria, total dissolved solids (TDS), suspended solids and chemical residuals	• Changes in water chemistry will influence the corrosion potential • Trends in dissolved metal ion concentration (e.g. Fe, Mn) can indicate changes in corrosion activity • Chemical residuals can be used to confirm the proper concentration of corrosion inhibitors • Sampling location and proper procedures are critical for accurate results
Production Monitoring	• Ongoing monitoring of production conditions such as pressure, temperature and flow rates • Ongoing monitoring of changes in water-oil ratio (water cut)	• Changes in operating conditions will influence the corrosion potential. Production information can be used to assess corrosion susceptibility based on fluid velocity and corrosivity • Increasing water-cut tends to have a higher likelihood of internal corrosion. Depending on a number of factors, typically a higher water-cut will lead to water wet steel surface. • Some liquid hydrocarbons will have better protective properties than others.

Technique	Description	Comments
Mitigation Program Compliance	• Ongoing monitoring of mitigation program implementation and execution	• Chemical pump reliability, injection rate targets and inhibitor inventory control are critical where mitigation program includes continuous chemical injection • The corrosion mitigation program must be properly implemented to be effective • The impact of any non-compliance to the mitigation program must be evaluated to assess the effect on corrosion
Corrosion Coupons	• Used to indicate general corrosion rates, pitting susceptibility, and mitigation program effectiveness	• Coupon type, placement, and data interpretation are critical to successful application of this method • Coupons should be used in conjunction with other monitoring and inspection techniques
Bio-spools	• Used to monitor for bacteria presence and mitigation program 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 bacteria levels • Consider following NACE TM0212 • Bacteria presence on pipeline internal 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, and field signature method	• The 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

7 Corrosion inspection techniques

Table 6 describes common techniques to be considered for the detection of internal corrosion in oil effluent pipelines.

Table 6: Corrosion inspection techniques

Options	Technique	Comments
Inline Inspection	• Magnetic flux leakage is the most common technique	• Inline inspection data should be verified using other methods • Effective method to determine location and severity of corrosion along the steel pipelines • Inline inspection can detect both internal and external corrosion wall loss as well as other types of imperfections • The pipeline must be designed or modified to accommodate inline inspection • The tools are available as free swimming or tethered • 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	• Evaluation must be done to determine potential corrosion sites prior to conducting NDE (see NACE SP0116 Multiphase Flow Internal Corrosion Direct Assessment Methodology for Pipelines) • NDE is commonly used to verify inline inspection results and corrosion at excavation sites. NDE methods may be used to measure corrosion pit growth at excavation sites, however the practical limitations of NDE methods and the factors affecting accuracy must be understood. • The use of radiography is an effective screening tool prior to using ultrasonic testing • Corrosion rates can be determined by performing periodic NDE measurements at the same locations
Video Camera/ Boroscope	• Used as a visual inspection tool to locate internal corrosion	• Can be used to determine the presence of corrosion damage, but it is difficult to determine severity • This technique may be limited to short inspection distances

Options	Technique	Comments
Destructive Examination	• Physical cut out and examination of sections from the pipeline	• Consideration should be given to locations where specific failure modes are most likely to occur. (see NACE SP0116 Multiphase Flow Internal Corrosion Direct Assessment Methodology for Pipelines)

8 Repair and rehabilitation techniques

Table 7 describes common techniques for repair and rehabilitation of pipelines damaged by internal oil effluent corrosion.

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

- CSA Z662, Clause 10 Including Temporary and Permanent Repair Methods
- CSA Z662 Clause 13 Reinforced composite, thermoplastic-lined, and polyethylene pipelines

Table 7: 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 as well as 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) • The replaced pipe section should be coated with corrosion inhibitor prior to commissioning or coated with an internal coating compatible with the existing pipeline
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. The sleeves must meet the requirements of CSA Z662 Clause 10

Technique	Description	Comments
Thermoplastic Liners	• A polymer liner is inserted in the steel pipeline • The steel pipe must provide the pressure containment capability	• A 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 • Reduction of inhibition programs may impact the integrity of connecting headers and facilities constructed from internally bare carbon steel
Composite or Plastic Pipeline	• Freestanding composite or plastic pipe can be either 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 pipelines are typically limited to low-pressure service • Impact on pigging capabilities and pig selection must be considered • Composite or plastic pipelines may eliminate the need for internal corrosion mitigation, corrosion monitoring and inspection • Reduction of inhibition programs may impact the integrity of connecting headers and facilities constructed from internally bare carbon steel
Entire Pipeline Replacement	• Using internally coated steel pipeline systems with an engineered joining system should also be considered • The alteration or replacement of the pipeline allows for proper mitigation and operating practices to be implemented	• Should be pig and inspection tool compatible (required for sour systems per CSA Z662 Clause 16) • Refer to Section 4 "Recommended Practices " in this document for details • Ensure that when replacements in kind occur, the replacement of the pipeline allows for proper mitigation and operating practices to be implemented