COATINGS FOR PIPELINES

Sankara Papavinasam and R.Winston Revie

CANMET Materials Technology Laboratory
Natural Resources Canada
568 Booth Street
Ottawa, Ontario
Canada K1A 0G1

Email: spapavin@nrcan.gc.ca and wrevie@nrcan.gc.ca

Abstract

Recent R&D on pipeline coatings is discussed, and the main R&D issues at this time in the area of pipeline coatings are identified.

Following are the main priorities for R&D at this time:

- Field applied coatings, both repair and joint coatings;
- Effects of minor variations in surface preparation on long-term coating performance;
- Relationship between application temperature and coating performance;
- Effect of compaction produced by backfilling on coating performance;
- Effects of physical and chemical soil forces on coating performance;
- Development of tests to evaluate repair coatings;
- Development of an industry-wide database on historical performance of older and modern coatings;
- Effects of microbial species on coating performance; and
- Methodologies for evaluation and qualification of external pipeline coatings for construction (-45°C) and usage (150°C) at extreme temperatures.

Introduction

Coating performance depends on the events taking place during the five stages of the coating lifetime:

1. Manufacture,
2. Application,
3. Transportation,
4. Installation, and
5. Field operation.

Objectives of R&D are to clarify the following issues[1-3]:

- What are the chemical and electrochemical conditions and their changes under realistic pipeline environments?
- What are the conditions that are independent of coating type?
- What are the conditions that depend on coating type?
- What are the failure modes of coatings on an operating pipeline?
- How are the failure modes identified?
- How accurate are the field monitoring techniques?
- Do the standard tests simulate the chemical and electrochemical conditions of the field environments?
- Do the standard laboratory tests simulate the failure modes in the field?
- Are the acceleration effects (e.g., aging, extreme CP potential, and elevated temperature) in the laboratory tests relevant to field conditions?
- What information from the laboratory data could be transferred to field performance?
- What are the assumptions to be made to transfer the data?
- How is the validity of the prediction of field performance monitored and verified in the field?

The state-of-the-art on our understanding of performance of pipeline coatings is discussed in this white paper, along with R&D to be performed to address the issues.

Manufacture of Chemical Components

Figure 1 lists the coatings used in different time periods in the twentieth century[4-64]. A comprehensive laboratory analysis of factors leading to coating failure[63] and loss of adhesion[64] has been performed. Some of the earliest coatings applied are still in service and are still available for application on new pipelines. Over a decade ago, the concept of polyurea spray elastomer technology was introduced. This new application was based on the reaction of an iso-cyanate component with an amine blend. Advances in both the chemistry and application equipment for coatings have enabled continuous evolution of coatings.

Coating Chemistry

The relationship between coating chemistry and corrosion protection is not clear. Objective investigations have been undertaken in the past to advance the knowledge of cathodic protection systems and the disbonding of coatings on buried pipelines by focusing on the electrochemical reactions and chemical changes that occur in the environment at the steel surface and to characterize, using Auger electron spectroscopy (AES) and X-ray photoelectron spectroscopy (XPS), the surface chemistry of steel samples taken from areas where the coating was disbanded. Simple test procedures have been developed to assess[65]:

1. The degree of reaction (cure) of the applied FBE coating,
2. The adhesive bond strength of the coating to the steel pipe substrate, and
3. The void content of the coating created by bubble entrapment or gas formation during application.

All investigations were carried out using FBE coating as the model system[66-72].

Filling the gaps in knowledge requires that the manufacturers be willing to disclose not only the coating formulations but also the ratios in which the different components are present in the formulations. Within the composition range of generic coatings, the formulations change widely without any significant change in the corrosion protection properties. Although a relationship between coating chemistry and corrosion protection is important, any attempt to fill this gap will involve significant R&D.

- The relationship between coating chemistry and corrosion protection is not clear.

Laboratory Evaluation

Evaluation of existing coatings is the first important step in the development of future coatings. Several methods have been used over the years to evaluate the tests. Table 1 presents a list of standard tests that can be used to evaluate coatings. It is not entirely clear which laboratory tests should be used to evaluate a particular property of a given coating and which laboratory tests are suitable for specific coatings.

- Consolidation of laboratory methods to develop generic tests, leading to specific test methods for specific coatings, should be considered.

Long-Term Prediction

Current and potential distributions inside the crevice of a simulated disbonded coating with a holiday during cathodic protection (CP) of steel were measured experimentally[73]. Based on the comparison of experiments and numerical simulation of a cathodically protected buried pipe with coating failures, a model was developed. The agreement between the results demonstrates that numerical simulations are acceptable for cathodic protection systems in high-resistivity media[74].

The two and three-dimensional boundary element mathematical models have been developed to model the performance of CP designs. The model offers a convenient tool to quantify the performance of a CP system and allows the user to determine the influence of relevant parameters (e.g., soil resistivity, coating damage, and anode type and spacing). The model can also be used as an educational tool to identify the factors that control CP performance under different operating conditions[75].

A boundary element mathematical model was used to assess the influence of cathodic protection (CP) design parameters on performance of a parallel-ribbon sacrificial anode CP system for coated pipelines. The model accounted for current and potential distributions associated with discrete holidays on coated pipelines that expose bare steel to the environment. Case studies, based on the CP system used to provide protection to the Trans-Alaska pipeline, were selected to show conditions under which a given CP system will and will not protect a pipe[76].

The General Electromigration Model (GEM) has been used with modifications for electrochemical kinetics[77]. The cathodic hydrogen evolution rate and anodic iron dissolution rates were both found to affect the pH inside the crevice. The model also predicted that formation of iron carbonate, observed extensively in some pipeline failures, occurs under a specific combination of iron dissolution rate and hydrogen evolution rate. GEM provides a unique modeling tool because it is flexible enough to test the effects of a variety of environmental conditions as input parameters and because its predictions of solid mineral formation in crevices can be tested against field experience. The changes in crevice pH and potential were measured experimentally using microelectrodes.

The occurrence of corrosion and stress corrosion cracking (SCC) under a disbonded coating on a pipeline is determined by a variety of factors including groundwater composition, soil conditions, presence of alternating wet/dry conditions, coating type, cathodic protection, and operating conditions. The Transient Electrochemical Coupled TRANsport (TECTRAN) code predicts the time evolution of the environment under a disbonded coating[78].

However in all the modeling work, the plurality of coatings has not been addressed. In one study, it was determined that for the coating thicknesses examined and over the time period observed, coal tar enamel and polyethylene tape acted as inert barriers, and no permeation or ionic migration through these coatings was observed. The FBE exhibited slight ionic migration and was found to be cation selective[79].

Electrochemical Impedance Spectroscopy (EIS) is a good tool to investigate the deterioration of coating on a metal. For gas pipelines, the equivalent circuit parameters in the presence of disbonded coatings have been well established[80]. Model parameters are coating thickness and the area under disbonded coating. A coated pipeline can be modeled as a sequence of simple equivalent circuits, which can be handled using standard theory to yield the observed impedance in terms of the values of the circuit elements in the line. The proposed models have been tested to verify their applicability for predicting sites of corrosion in buried pipelines. The effect of a few geometrical and physical parameters has been investigated, and results have been compared with the output of laboratory and field measurements. In some cases, the adjustment of literature parameters has been enough to obtain good agreement of field and laboratory data; modification of the equivalent circuit has, however, been found to be necessary. Future work in this field is promising.

Electrochemical impedance spectroscopy provides two very important pieces of information: the change in capacitance of the organic film that relates to water uptake and the deviation from purely capacitive behavior of the film.

Development of virtual pores in the coating or disbonding of an electrolyte-saturated film at the onset of corrosion causes deviation from capacitive behavior. For either case, conducting paths develop parallel to the coating. Qualification of these conduction paths predicts coating life in corrosive environments as shown by the few available studies that have actually compared impedance data to long-term exposure. Research to evaluate the nature of the shorting process would provide valuable insight into the degradation of the protective properties of organic coatings. Despite some transmission-line models, little understanding exists on the relationship of the low-frequency data to the protective properties of organic coatings.

Low cost computing power is having its impact on all areas. In recent years, the use of microprocessors in the design of instrumentation has brought computing power into the hands of people working in quality control. These analytical techniques are now being applied to coatings, particularly for coating thickness assessment when continuous processing is applicable.

- A comprehensive model to predict long-term performance of coatings should be developed based on carefully controlled laboratory experiments as well as from field experience with older coatings, such as coal tar and asphalt, and modern coatings, such as FBE and urethane, using the power of modern computers and intelligent systems, e.g., artificial neural networks.

Temperature Effect

In some applications, one of the critical properties of external organic coatings is resistance to high temperature. It has been found that most organic coatings have problems at temperatures higher than 80°C. There is a need for high-temperature performance in oil and gas pipelines, especially near compressor stations for natural gas transmission and in the transport of higher viscosity crude oils. The operating temperatures of pipelines extend to 150°C. Applicators, coating manufacturers, and owners are working to overcome the challenges associated with high temperatures. Currently no industry standards exist to test high temperature coatings. Manufacturers are developing high temperature coatings based on in-house testing. It is recognized that conventional test methods, such as cathodic disbondment, may not be appropriate. The primary challenge is to obtain adequate flexibility with high temperature performance. For this reason, design criteria for high temperature test methods and for life prediction need to be established.

The criteria for testing coatings for higher temperature applications are not the same as those for lower temperature application. For example, coatings with good cathodic performance, adhesion, barrier properties, impact resistance, and flexibility will protect the pipeline over the lifetime. At elevated temperatures, cathodic disbondment performance may not be relevant if the coated pipe is insulated. But good adhesion, barrier poperties, flexibility, and resistance to movement at higher temperatures are necessary.

The question, is not “How do we design the perfect high temperature coating?” Rather it is “How do we know that we have designed it?”

- Based on a systematic study, the temperature limits of existing tests should be explored, and tests to evaluate products for elevated temperature applications should be developed.

Application

In general, conditions are better for application of coatings in the mill than in the field. Most modern coatings are applied in the mill.

- Whereas many of the issues of mainline coatings are well understood and standards for mainline coatings have been developed, there is now a need to focus on field applied coatings, both repair and joint coatings.

Surface Preparation

Resistance of a coating to disbondment is a property affecting all forms of corrosion; an intact coating that prevents contact of electrolyte with the steel surface will mitigate all forms of corrosion. Studies show that inadequate grit blasting can increase corrosion and stress corrosion cracking susceptibility by creating stress raisers at embedded mill scale. Grit blasting produces anchor patterns suitable for adherence of coatings.

A study of atmospheric exposure of cold applied coal tar enamel coatings revealed that systems applied to wire-brushed surfaces, primed or unprimed, failed within one year. On the other hand, the same systems on sandblasted surfaces, with and without primers, were in satisfactory condition after five years' exposure in the same environment[81].

Studies have concluded that visual evaluation (degree of blistering, rusting and creep of blistering and corrosion from a scratch) is not sufficient to predict the effect of surface condition on coating properties[82].

An investigation on the effect of surface contamination included a study of the presence of varnish or previous coating on the pipe, phosphoric acid treatment, water, and grit or shot quality. The presence of contaminants on the pipe surface was identified using EDAX (X-ray energy dispersion analysis), optical and electron microscopy analysis, grit and water conductivity, and acid wash location. The results indicate that all varnished pipes presented high cathodic disbonding (above 17 mm). This high cathodic disbonding was attributed to varnish particles located on the anchor pattern of the pipe surface. It was also found that the phosphoric acid application after blasting gives better adhesion and less cathodic disbonding. This has been attributed to the surface active pattern provided by the acid that gives better interaction between the pipe surface and FBE[83].

Based on R&D to evaluate the performance of FBE coatings on contaminated and uncontaminated surfaces with and without phosphoric acid treatment, the following conclusions were drawn[84]: Acid wash treatment greatly improves the performance in CD tests if the surface was initially contaminated. Chloride contamination is the most difficult type of contamination to remedy due to pitting corrosion.

Based on adhesion ratings after hot-water immersion, the maximum tolerance levels of FBE coatings[85] applied over contaminated steel surfaces were at the threshold limit values: chloride (5 $\mu g/cm^2$), sulphate (7 $\mu g/cm^2$), nitrate (9 $\mu g/cm^2$), and ferrous ion (24 $\mu g/cm^2$). Accelerated performance testing of FBE coatings on ion-contaminated steel substrates revealed that the following coating parameters are functions of contaminant ion concentration: (1) tensile bond strength after hot-water immersion, (2) blister size and density after hot-water immersion, and (3) degree of disbondment after accelerated cathodic disbonding. One study of FBE coating performance was conducted using coupons removed from contaminated production pipe. The steel coupons with contaminations higher than a threshold level failed in the hot-water immersion test, whereas those with lower levels of contamination passed the test.

The use of water jetting and water cleaning has increased recently with advances in equipment technology, the continued concerns with dusting caused by abrasive blast cleaning, and a heightened awareness of the need for chemically clean substrates. NACE 5/SSPC-SP 12 was introduced in 1996 (as an update to NACE Standard RP0172) to describe levels of cleaning using water for substrates to be painted. The NACE and SSPC abrasive blast cleaning standards are well known in the coatings industry, and field inspectors are very familiar with their use and interpretation. Additionally, the blast cleaning standards clearly describe one end condition of the substrate to be painted. In contrast, NACE 5/SSPC-SP 12 describes four end conditions of the substrate for visible cleanliness and three conditions for non-visible cleanliness. As a result, the specifier must make specific choices when invoking NACE 5/SSPC-SP 12.

A review paper on the surface preparation standards in various countries was published recently with the intention of determining whether there is a prevailing or common standard in use. Discussions with users in Europe, United Kingdom, Middle East, Japan, Australia and Venezuela have revealed a trend away from national standards towards International Standards[86].

Grit blasting increased the disbonding resistance of coal-tar enamel and FBE coatings, but did not increase the cathodic disbonding resistance of polyethylene tape. Grit blasting also beneficially alters the corrosion potential of the pipe[87].

Whereas the effects of different surface preparation techniques are well established, the tolerance in the variation within the surface preparation specification is not clear. This aspect is especially important because there are limitations on the control of surface preparation that is possible in the field.

- The effects of minor variations in surface preparation on long-term coatings performance need to be established.

Temperature Effects

The intercoat adhesion of coatings cured using cross-linkers depends on both temperature and humidity. The addition of thinner aggravates intercoat adhesion failure. The conversion of the amine to amine carbamate salts at or near the surface, resulting in incomplete curing at the interface, is responsible for intercoat adhesion failure.

The rate of reaction between the amine and the epoxy prepolymer, and the humidity level, are key factors in the intercoat adhesion of epoxy coatings. At appropriate temperatures of application, the rate of reaction between the amine and the epoxy prepolymer is rapid, causing the formation of coatings with good intercoat adhesion. However, at lower temperatures, the rate of the cross-linking reaction is decreased, allowing moisture to permeate the coating and solubilize the amine. In its solubilized form, the amine reacts with carbon dioxide to form stable carbamate salts incapable of reacting with the epoxy prepolymer. In addition, the degree of cross-linking also depends on the RH level to determine the degree of solubilization of the amine that can be converted to the carbamate salt. The appropriate level of applying the coating is generally determined by the glass transition temperature[88].

- The relationship between application temperature and coating performance needs to be established.

Installation of Pipeline

During installation, minor coating damage is bound to occur for various reasons. It is very important to ensure that the pipe coating is adequately tested and that all defects are repaired.

Stockpiled Coating

The breakdown of powder polyester coatings when exposed to UV radiation (270-390 nm, peak ~313 nm) has been explored by monitoring changes in their ion transport properties using impedance spectroscopy. EIS demonstrated that one manifestation of weathering was the development of an increased level of porosity in the films that could be measured quantitatively. The results from impedance spectroscopy were supported by SEM and gloss loss measurements[89].

The effect of UV on stockpiled coatings is well known. The extent to which stockpiling affects coating performance is not known.

- Influence of stockpiling on coating performance should be established.

Joint Coating

Historically, the major problems associated with field applied coatings were directly related to the sensitivity of prevailing environmental conditions, such as substrate cleanliness and preparation, and application technique. In addition to good "in service" performance, systems should be easy to apply and tolerant to environmental conditions. While pipeline coating plants have been developed to apply advanced coatings to strict specifications, specifications for coatings applied to field joints have not received the same emphasis.

The increase in use of high quality and expensive pipeline coatings has heightened the need for field joint coating systems to match the quality of factory coatings. A comparison should be made between the different field joint coating systems in terms of technical characteristics, cost, and ease of application in the field. Because of the lack of international standards, pre-qualification trials and production testing in the field are important.

- A systematic study on the effects of field conditions and variations of procedure during the application of joint coatings, including the field performance of the coating, is recommended. This study should include the cohesive and adhesive strength of joint coatings.

Backfilling

There are several factors relating to backfilling that influence coatings. These are soil type, drainage, topography, temperature, and electrical conductivity. The Canadian Energy Pipeline Association (CEPA) has classified the soils in Canada into seven (7) types (Table 2). Even though backfilling is very important, no systematic experimental data are currently available on the effect of backfilling on coating performance.

Fine backfill around the pipe is used to protect the pipe from heavy and sharp rocks or other objects. In addition, the system can include a layer of geotextile fabric just above the fine backfill as additional protection against damaging rocks[90].

In very rocky areas, pipeline-construction operations sometimes dictate that an external impact-resistant or barrier material be applied over the pipe to protect the coating from damage during backfilling. The use of a specific backfill, such as compacted sand, is often specified. As an alternate, a barrier coating of concrete or urethane foam can be applied over the coating.

Although high resistance and resistivity are normally associated with a propensity for shielding of cathodic protection current, the resistivity of a barrier material and the corrosion rates and polarization characteristics of the underlying steel are important when considering the potential for shielding and the protection capability of the barrier material[91].

- Realistic backfill impact testing that includes a method to evaluate the compaction produced by backfilling should be carried out to determine the effect of backfilling on coating performance.

Soil Forces

Shear properties of pipeline coatings with elastomeric adhesives are frequently measured in the laboratory. These measurements are expected to correlate with the ability of the coating to withstand the forces of soil burial and movement. The parameters of the laboratory methods are based on calculations of soil forces on pipeline coatings from an analytical model and from finite element analysis[92].

An apparatus was designed and built to carry out peel and sheer tests at different temperatures. The peel test procedure allows for the measurement of shear strength, which is directly comparable to shear stress sustained by coatings on buried pipelines. The results have shown significant differences between the adhesion properties of individual products. The shear and peel strengths of the coatings are strongly affected, as shown by an exponential drop with increasing temperature. The results conform to an Arrhenius relationship between temperature and the peel and shear strengths[93].

In one project, existing test methods were examined to determine their applicability to horizontal directional drilling (HDD) and slip boring loads. Two generally applicable methods were identified, Technical Inspection Services' (TISI) Gouge Test and Taber Abraser Test (ASTM D 4060). Both these methods are related to the soil conditions, for which the rotary abrasion tester has been designed. The results can be used to predict coating wear during HDD installation through rock[94].

- Focused effort to understand soil forces (both physical and chemical) on coating performance will provide useful information for developing strategies to protect coatings.

Construction of Frontier Pipelines in Extreme Temperatures

In the near future, the construction of northern pipelines for transmission of natural gas will begin in North America. Construction in the harsh northern climate (temperature as low as – 45°C) and remote location will impose unique challenges with respect to pipeline protective coatings. Methodologies for evaluating and selecting pipeline coatings for use in northern pipelines will have to be developed, considering the extreme climatic conditions to which the coated pipe may be subjected before it is installed and before operation begins. It is critical that the design of coatings be adequate to protect the pipelines under long-term, severe environmental conditions, including the extreme climatic conditions that will apply in the North before the pipe is installed and operation begins.

- Recommended practices for evaluating coatings for northern pipelines need to be developed and incorporated in standards

Field Testing of Coatings

Repair Coatings

A number of factors that are important in the performance of mainline coatings are also important for repair coatings, including: cathodic disbondment, adhesion, resistance to moisture penetration, impact resistance, penetration resistance, performance at service temperature, abrasion resistance, soil stress, burn-back resistance, chemical resistance, and general handling behavior. In addition, because the repair coatings are applied in the field, the factors discussed in joint coatings are also important. In spite of the importance of repair coatings, no special tests or procedures have been developed to evaluate them[95].

Correct material selection can provide substantially improved coating performance and economy. No specific method for repair coating selection exists. The development of field-proven, reliable criteria for selecting and evaluating repair coatings is essential in order to make the best use of available materials and processes. The development of accelerated tests that closely resemble actual field application and service conditions would be useful in the realistic evaluation of repair coatings.

- Tests to evaluate repair coatings, including evaluation of cohesion within the repair coating and adhesion to the mainline coating and to steel pipe, should be developed.

Field Performance

Monitoring

Several techniques are available to detect defects in coatings on buried pipelines. A critical review and evaluation of the Pearson survey, close interval survey, coating conductance parameter, electromagnetic current attenuation, and dc voltage gradient methods have been provided, with the advantages and disadvantages of each method identified[96]. An instrumented pipeline pig designed to locate disbonded external coating on operating gas pipelines has been evaluated[95]. The results from each method are assessed in terms of defining the need for coating refurbishment and in providing the parameters needed to establish the most cost-effective route to control pipeline corrosion.

The Elastic Wave vehicle has the potential to detect disbonding as well as areas where the coating has been removed[98,99].

The development of instrumentation for field testing and inspecting coatings has been accelerated by the use over the last ten years of microprocessor electronics. Such designs are now entering the fourth generation and have included many user features which make the assessment of coatings easier and more accurate than was previously possible. These features include storage of data, statistical analysis, hard copy printout and high accuracy in hand-held fully portable and rugged units, suitable for use in the most hazardous environments. The most recent improvements have been realised by providing the transducer or probe with electronic intelligence so that its characteristics can be closely matched for optimum accuracy and flexibility. A major benefit of this approach is that the measurement transducer can be of any type and the data output from the electronics can be made to fit a standard format display instrument. In this way, it is possible to make a general purpose kit with a diverse set of measurement modules for a range of tests, such as temperature, humidity, surface profile, and adhesion, as well as a full range of coating thickness modules, using electromagnetic induction and eddy currents for applications that range from thin coatings on small components up to very thick coatings on large structures.

It is becoming more common for gas transmission pipelines to share a common corridor with electric power-transmission lines. Electrical energy that is magnetically coupled from the power line often results in an ac voltage being developed between the pipeline steel and the earth that surrounds the pipeline[100].

EIS can be used to measure coating degradation, corrosion under coatings, and cathodic delamination. The EIS method deserves further investigation for measurement of the degradation of coatings during field exposure.

- Development of a remote, accurate monitoring technique to evaluate the status of the coating will greatly enhance pipeline integrity and decrease the number of pipeline incidents caused by corrosion.

Feedback

In spite of the close interaction between pipeline owners and coating suppliers at the time of installation of pipe, feedback on coating performance, whether positive or negative, is not, in general, readily available.

- Development of an industry-wide coating database to share the experience of older and modern coatings is an essential logical step to develop an integrity management program. Continuous updating and sharing of such a database will be very useful.

Operational Conditions

In general, pipeline operational conditions vary considerably. Among all the various conditions, temperature is quite important. In spite of the well-known temperature variations of pipelines and seasonal fluctuations, no systematic study on the effect of temperature on coatings has been carried out.

- The performance of coatings should be compared at constant and fluctuating temperatures.

Ground Effects

Although coatings are routinely evaluated for resistance to a variety of ground factors (e.g., soil stresses), few coatings have been developed with consideration given to their resistance to microbiologically influenced corrosion (MIC). Increased numbers of bacteria at some corrosion sites have been observed. A model, for the development of a site where MIC occurs, indicates that, in the first phase, soil stresses cause disbondment of the coating, leaving adhesive/primer exposed to the invading water on the pipe surface. Blisters, filled with water, form in the residual coating components on the pipe surface. As the MIC community forms and grows, pitting corrosion begins in those local areas, effectively "fixing" the anodes. In the final phase, periodic exposure to oxygen results in secondary transformation of the corrosion products (siderite and ferrous sulfides) to iron (III) oxides.

Early studies performed in the GRI MIC program demonstrated that a very high percentage of external MIC occurred in connection with disbonded coatings and followed the same general pattern as classic examples of MIC associated with disbonded coatings. The general consensus is that holidays will occur in most coatings by one or more mechanisms (mechanical, chemical, and biological) and that holidays and disbonded coatings offer sites for MIC to occur[101]. Studies have also shown that levels of bacteria are high on all types of coatings and in all holidays regardless of the level of CP and the pH in the holidays (which ranged from 4.5 to 11.9).

The effects of CP on MIC cannot be assessed simply by measuring the numbers of bacteria. Instead, chemical and site specific factors (e.g., corrosion potential of the steel in the soil) must be taken into account.

A "first-cut" MIC profile was developed to aid in determining which sites were most likely to be susceptible to external MIC. This profile included soil, chemical, biological, metallurgical and operational factors, such as level of CP.

Several reports in the literature have confirmed the utilization of certain pipeline coatings by microorganisms. Microorganisms have the potential to enhance coating disbondment rates as well as contribute to pipeline corrosion as a result of coating biodegradation. Tests used parameters such as coating weight loss and enumeration of microbial cells to assess the biodegradation of coatings. Uncertainties in causes of weight change occur because weight loss can result from solubilization of coating constituents and weight gain can be caused by water absorption. Enumeration is not a measure of activity since microorganisms can be active without increasing their numbers. Thus, enumeration cannot produce direct and quantitative results.

- An objective study to develop a method that monitors microbial population and coating biodegradation will clarify the effects of microbes on coatings.

Summary

The following R&D issues have been identified as top priorities[102]:

- Whereas most of the issues surrounding mainline coatings are well understood and the standards for mainline coatings are recognized, the focus should now be on field applied coatings, both repair and joint coatings.
- The effects of minor variations in surface preparation on long-term coatings performance need to be established.

- The relationship between application temperature and coating performance needs to be established.
- Methods to evaluate the compaction produced by backfilling should be developed to determine the effect of backfilling on coating performance.
- Focused effort to understand soil forces (both physical and chemical) on coating performance will help develop strategies to protect coatings.
- Tests specifically to evaluate repair coatings, including evaluation of cohesion within the repair coating and adhesion to the mainline coating and to steel pipe, should be developed.
- Development of an industry-wide coating database to share the experience of older and modern coatings is an essential logical step to develop an integrity management program. Continuous updating and sharing of such a database will be very useful.
- An objective study to develop a method that monitors microbial population and coating biodegradation will clarify the effects of microbes on coatings
- Methodologies for evaluation and qualification of external pipeline coatings for construction (-45^0C) and usage (150^oC) at extreme temperatures need to be developed.

Acknowledgements

The authors gratefully acknowledge the support of the Pipeline Research Council International (PRCI) in carrying out the review described in this white paper. Numerous helpful discussions with the chair of the Ad Hoc PRCI committee, Howard R. Mitschke of Shell Global Solutions (US) Inc., are acknowledged. Meetings with the Ad Hoc Committee were most beneficial in helping to achieve the objectives of this project.

References

1. S.Nunez, K.E.W.Coulson, L.C.Choate, and J.L.Banach, "A Review of Gas Industry Pipeline Coating Practices", July 1988, A.G.A. Catalog No. L51586.
2. S.J.Lukezich, J.R.Hancock, and B.C.Yen, "State-of-the-Art for the Use of Anti-Corrosion Coatings on Buried Pipelines in the Natural Gas Industry", April 1992, Gas Research Institute Project # 06-3699 (GTI #2024/GRI-92/0004) and "Prediction of the Field Performance of Anti-Corrosion Coatings for Buried Steel Pipelines" International Gas Research Conference 1992, p. 512 (GT9 #2024).
3. A.Andrenacci, D.Wong, and J.G.Mordarski, "New Developments in Joint Coating and Field Repair Technology", Materials Performance (2) (1999), p.35.
4. Aalund, L.R., Polypropylene System Scores High as Pipeline Anti-corrosion Coating, Oil & Gas Journal, (1992) 42-45.
5. Alexander, M., High-Temperature Performance of Three-Layer Epoxy/Polyethylene Coatings, *MP*, (1992) 41-45.
6. Appleman, B.R., Tape Systems for Pipeline Protection, J.Protective.Coatings and Linings, 4 (1987) 52-60.
7. Arai, T and Ohkita, M. Application of Polypropylene Coating System to Pipeline for High Temperature Service. 189-201. 1989. Florence, Italy, BHRA (Information Services), The Fluid Engineering Centre, Cranfield, Bedford MK43 0AJ, UK, 1990.

Internal and External Protection of Pipes–Proceedings of the 8th International Conference.
8. Arai, T., Ohkita, M., Ohtsuka, T.and Yamauchi, S., Development of an Ultraviolet Curable Primer (UVC) System for Polyethylene Coated Steel Line Pipe, Sumitomo Search, (1987) 77-82.
9. Banach, J L. Pipeline Coatings - Evaluation, Repair, and Impact on Corrosion Protection Design and Cost. 29-1-29/13. 1987. Houstan/Texas, NACE. Corrosion 87.
10. Bennett, K., Selecting Field Joint Coatings for Two- and Three-Layer Extruded Pipe Coatings, Journal of Protective Coatings & Linings, 18 (2001) 45-49.
11. Blome, P.nd Friberg, G., Multilayer Coating Systems for Buried Pipelines, Materials Performance, 30 (1991)
12. Connelly, G, Gaillard, G, and Provou, Y. Three Layer Epoxy--Polypropylene Pipe Coatings for Use at Elevated Service Temperatures. 179-188. 1989. Florence, Italy, BHRA (Information Services), The Fluid Engineering Centre, Cranfield, Bedford MK43 0AJ, UK, 1990. Internal and External Protection of Pipes--Proceedings of the 8th International Conference.
13. Connelly, G. and Gaillard, G. 3 Layer Polyolefin Pipe Coatings. UK Corrosion 87(Coatings and Linings: Pipeline Protection - Multi Layer Coating Systems), 1-14. 1987. Institute of Corrosion. Conference Archive CD 1982-1999.
14. Cox, J.W.nd Fogh, K., Dual Coating System for Pipelines in High-Temperature Service, Materials Performance, 29 (1990) 18-21.
15. Dempster III, W. A. and Doheny Jr., A. J. Heat Fused Polyolefin System For Fusion Bonded Epoxy Coated Pipe. 564-1-564/11. 1994. Houstan/Texas, NACE. Corrosion 94. 1994.
16. Didas, J., Fusion-bonded Epoxy Coatings for Underground Pipelines, Materials Performance, 39 (2000) 38-39.
17. Duvic, N. C. Polysiloxanes-New Coating Technology. 582-1-582/6. 1988. Houstan/Texas, NACE. Corrosion 95. 1995.
18. Y Ikeda. The Development of Embossed Polyethylene Coated Pipe for Offshore Pipelines. 1-10. 1983. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. 5th International Conference on the Internal and External Protection of Pipes, Innsbruck, Austria, 25-27 Oct. 1983.
19. Fairhurst, D. and Willis, D. Polyporpylene Coating Systems for Pipelines Operating at Elevated Temperatures. UK Corrosion 95(Session 1: Pipe Protection - Recent Coating Developments), 1-24. 1995. Institute of Corrosion. Conference Archive CD 1982-1999.
20. Funatsu, S. Durability of three layer polypropylene coated steel pipe at elevated temperatures. 9-11. 1995. Florence, Italy, Mechanical Engineering Publications Ltd., P.O. Box 24, Northgate Avenue, Bury St. Edmunds, Suffolk IP32 6BW, UK, 1995. Eleventh International Conference on Pipeline Protection.
21. Gaillard, G and Connelly, G. 3 Layer Epoxy-Polyolefin Pipe Coatings. 309-1-309/13. 3-25-1988. Houstan/Texas, NACE. Corrosion 88. 3-21-1988.
22. Ganga, R., Thermoplastic Coating Used on Oman Hot Liquids System, Pipe Line Ind., 53 (1980) 83-84.
23. VGoff, B C. The Coating of Pipeline Field Joints - The State of the Art and a Look to the 1990's. UK Corrosion 89(Coatings and Linings in Field Experience), 1-16. 1989. Institute of Corrosion. Conference Archive CD 1982-1999.

24. Goff, B C and Strobel, R F. The Development of Fusion-Bonded Epoxy Pipeline Coatings in Europe and the Middle East. 17-30. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.
25. Hankins, E E. Development of Tapes for the External Protection of Pipelines in High-Temperature Environment. 317-328. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.
26. Hankins, E E. The Role of Plastics in Pipeline Protection Tapes. 1980. Plastics and Rubber Institute, 11 Hobart Place, London SW1W OHL, England. Plastics and Paints Against Corrosion, London, England, 12 Nov. 1980.
27. Harris, M. T. and Argent, C. J. A Review of the Factors Influencing the Mechanical Properties of Epoxy Powder Coatings. 127-150. 1985. Institution of Corrosion Science and Technology, Exeter House, 48 Holloway Head, Birmingham B1 1NQ, UK. UK Corrosion '85: Coating and Preparation, Corrosion Monitoring, Materials Selection, Harrogate, UK, 4-6 Nov. 1985.
28. Ireland, Y. M. and Lopez, A. Field Application of Epoxy-urethane Coatings Using Line Travel Equipment on Pipelines. 00771-1-00771/15. 2000. Houston, Texas, NACE International. NACE Corrosion 2000. 3-26-2000
29. Johnson, J. R., Henegar, S., and Roder, B. a New Higher Temperature Coal Tar Enamel Pipeline Coating System. 196-1-196/12. 1996. Houston, Texas, NACE International. NACE Corrosion 96. 3-24-1996.
30. Johnston, B.R., Polyethylene Coating of Steel Pipe Experience Gained in the Development of a "Tight- Bonding" System, Institution of Corrosion Science & Technology, Exeter House, 48 Holloway Head, Birmingham B1 1NQ, UK", 1987,
31. Kehr, J. A. FBE Pipeline and Rebar Corrosion Coatings. April 10, 2000. 2000. http://www.NRCan.gc.ca/picon/conference2/kehr2.htm, Natural Resources Canada - CANMET. 2000 PICON Conference. and A Foundation for Pipeline Corrosion Coatings. 00757-1-00757/20. 2000. Houston, Texas, NACE International. NACE Corrosion 2000. 3-26-2000.
32. Kellner, J. D., Doheny Jr., A. J., and Patil, B. B. a New 3-layer Polyethylene Coating for Plant Application. 557-1-557/10. 1997. Houston, Texas, NACE International. NACE Corrosion 97. 3-14-1997.
33. Klahr, W. Polyurethane/Tar Coating for Steel Pipes. 51-66. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.
34. Knight, W.J., Polyurea Spray Coatings: An Introduction, Journal of Protective Coatings & Linings, 18 (2001) 48-52.
35. Marchal, R. Protection of Buried Ductile Iron Pipelines With a Zinc-Based Coating-Healing Power of Coating Damages. 125-137. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.
36. Murakami, M. Influence of epoxy primer on polyethylene coating properties. 139-168. 1995. Florence, Italy, Mechanical Engineering Publications Ltd., P.O. Box 24, Northgate Avenue, Bury St. Edmunds, Suffolk IP32 6BW, UK, 1995. Eleventh International Conference on Pipeline Protection.

37. Norman, D. and Swinburne, R. Epoxy and Polyurethane Coatings for the Rehabilitation and Repair of Pipelines. UK Corrosion 98, 08-01-08/14. 1998. Institute of Corrosion. Conference Archive CD 1982-1999.
38. Norman, D. and Swinburne, R. Polyurethane and Epoxy Coatings for the Rehabilitation and Repair of Pipelines. 00758-1-00758/7. 2000. Houston, Texas, NACE International. NACE Corrosion 2000. 3-26-2000.
39. Nozahic, D., Leiden, L., and Bresser, R. Latest Developments in Three Component Polyethylene Coating Systems for Gas Transmission Pipelines. 00767-1-00767/8. 2000. Houston, Texas, NACE International. NACE Corrosion 2000. 3-26-2000.
40. O'Donoghue, M., Garrett, R., Datta, V.J., Swanson, E.and Dillingham, B., Fast-Cure AHC Epoxy Coatings for Tank and Pipe Applications, Materials Performance, 39 (2000) 32-37.
41. Okano, Y., The development of an auto-sealing system using an electrically shrinkable tube under a low-pressure condition, Materials Performance, 36 (1997) 40-44.
42. Okano, Y., Shoji, N., Namioka, T., and Komura, M. The Development of Auto-sealing System for Field Joints of Polyethylene Coated Pipelines. 389-1-389/11. 1997. Houston, Texas, NACE International. NACE Corrosion 97. 3-14-1997.
43. Padley, T.J.nd Collins, H.H., The External Protection of Buried Ductile Iron Pipes by Polyethylene Sleeving, Advances in Pipeline Protection, (1988) 25-31.
44. Power, S. High Performance Liquid Epoxy Polymer Concrete Coatings Used for New Construction and Rehabilitation Projects. Paper 01606, 1606-1-1606/6. 2001. Houston, Texas, NACE International. Corrosion 2001.
45. Reeves, C. R. Pipeline Rehabilitation Using Field Applied Tape Systems. 615-1-615/6. 1998. Houston, Texas, NACE International. NACE Corrosion 98. 3-22-1998.
46. Rench, J.E., Review of a Fusion Bonded Pipeline Coating System, NACE Paper no 47, (1973)
47. Rigosi, G L, Marzola, R, and Guidetti, G P. Polypropylene thermal insulated coating for pipelines. 9-11. 1995. Florence, Italy, Mechanical Engineering Publications Ltd., P.O. Box 24, Northgate Avenue, Bury St. Edmunds, Suffolk IP32 6BW, UK, 1995. Eleventh International Conference on Pipeline Protection.
48. Roebuck, A. H. and Foster, R. W. 100% Solids Plural Component Urethane Coatings. 213-233. 1987. Orlando, Florida, USA, Steel Structures Painting Council, 4400 Fifth Ave., Pittsburgh, Pennsylvania 15213, USA", 1987. Conference: Improving the Field Reliability of Protective Coatings.
49. Singh, P. J. and Cox, J. Development of a Cost Effective Powder Coated Multi-component Coating for Pipelines. 00762-1-00762/14. 2000. Houston, Texas, NACE International. NACE Corrosion 2000. 3-26-2000.
50. Sloan, R.N.nd Hsu, L.L., Extruded Polyolefin Systems for Pipeline Protection Total Corrosion Control for Industrial Gas Turbines: High Temperature Coatings and Air, Fuel and Water Management, J.prot.coatings Linings, 32 (1987) 1-17.
51. Takamatsu, T., Suzuki, K.and Ishida, M., Polyurethane Elastomer Coated Steel Pipe for Water Service, Nippon Steel Tech. Rep., (1985) 49-57.
52. Tsuchiya, K, Ohtsuki, F, Tanaka, M, and Sugimura, S. An Approach Toward Heat Resistant Coating Material for Line Pipes. 307-316. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.

53. Tucker, J.G., Elastomeric Polyurethanes Use as Coatings in the Arduous Conditions of Severe Corrosion and Abrasion, Anti-Corrosion Methods Mater. 33 (1986) 10-13.
54. Ueno, T., Polyethylene Coated Pipe, Tube Int., 4 (1985) 101-105.
55. Van Eijnsbergen, J F H. External Corrosion Protection of Pipes by Modern Tapes. 139-148. 1981. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. Internal and External Protection of Pipes, Noordwijkerhout, Netherlands, 15-17 Sept. 1981.
56. Vemer, E.nd Fletcher, A., An introduction to fusion bonded low density polyethylene coatings for large bore steel pipe, Corrosion and Coatings, South Africa, 22 (1995) 6-8.
57. White, P A. The Development of Polymer Modified Glass Fibre Reinforced Cement as a Buffer Coating for the Mechanical Protection of Thin Film Anti-Corrosion Coatings. 97-120. 1983. BHRA Fluid Engineering, Cranfield, Bedford MK43 0AJ, England. 5th International Conference on the Internal and External Protection of Pipes, Innsbruck, Austria, 25-27 Oct. 1983.
58. Wilberg, I. E. Glassflake Reinforced Polyester Coatings, 10-20 Years Experience in USA, in the North Sea and Industrial Application. UK Corrosion 91(Symposium A: Coatings and Linings - Field Experience in Critical Areas), 1-26. 1991. Institute of Corrosion. Conference Archive CD 1982-1999.
59. Wood, B., Coal Tar Epoxy Coatings: "That Old Black Magic", Journal of Protective Coatings and Linings, 4 (1987) 32-38.
60. Zheng, F. Glass-Fiber Reinforced Plastics Wrap-Coating for Anti-Corrosion of Marine Steel Pipeline. 6-9. 1988. Xiamen, China, International Academic Publishers, Xizhimenwai Dajie, Beijing Exhibition Centre, Beijing 100044, China, 1988. Corrosion and Corrosion Control for Offshore and Marine Construction
61. D.P.Werner, S.J.Lukezich, “Selection and Use of Anti-Corrosion Coatings for Corrosion Control of Buried Natural Gas Pipelines”, 92-DT-63, p.125.
62. National Energy Board Report of the Inquiry, Stress Corrosion Cracking on Canadian Oil and Gas Pipelines, Calgary, Canada, December 1996
63. B.C.Brand, E.J.Bradbury, R.J.Dick, M.M.Epstein, J.A.Hassell, H.N.Johnston, J.F.Kiefner, W.Mirick, J.K.Moon, L.J.Nowacki, J.M.Spangler, and J.A.Wray, Line Pipe Coating Analysis Volume 1, Laboratory Studies and Results, November 1978
64. B.C.Brand, E.J.Bradbury, R.J.Dick, M.M.Epstein, J.A.Hassell, H.N.Johnston, J.F.Kiefner, W.Mirick, J.K.Moon, L.J.Nowacki, J.M.Spangler, and J.A.Wray, Line Pipe Coating Analysis Volume 2, Topical Report on Adhesion, November 1978.
65. MRI Report, “On-Site Assessment of Mill-Applied Fusion-Bonded Coating Quality”, February, 1985.
66. G.R.Ruschau and J.A.Beavers, “Performance of Blistered FBE Coated Pipe”, PR-186-9810, December 2000.
67. J.H.Payer and J.J.Perdomo, “Chemical and Electrochemical Conditions on Steel on Disbonded Coatings”, PR 75-9310, 1995
68. J.H.Payer, “Fundamental Research on Disbonding of Pipeline Coatings”, GRI-92/0166/GTI2110, 1992
69. M.Kendig, J.Lumsden, P.Stocker, and S.Jeanjaquet, “Mechanism of Disbonding of Pipeline Coatings” GRI-93-0230
70. M.Kendig, J.Lumsden, P.Stocker, and S.Jeanjaquet, “Mechanism of Disbonding of Pipeline Coatings”, GRI-92/0173/GTI2115
71. M.Kendig, “Mechanism of Disbonding of Pipeline Coatings”, GTI #2115/GRI-95/0459

72. D.Gervasio, I.Song, B.Trautman, and J.H.Payer, "Fundamental Research on Disbonding of Pipeline Coatings", GRI-93/0265/GTI2110
73. Chin,D.-T.; Sabde,G."Current Distribution and Electrochemical Environment in a Cathodically Protected Crevice", Corrosion 55 (3), 1999, p.229.
74. Brasil,S.L.D.C.; Telles,J.C.F.; Miranda,L.R.M., "Simulation of Coating Failures on Cathodically Protected Pipelines - Experimental and Numerical Results" Corrosion 65 (11), 2000, p. 1180.
75. Esteban,J.M.; Orazem,M.E.; Kennelley,K.J.; Degerstedt,R.M., "Mathematical Models for Cathodic Protection of an Underground Pipeline with Coating Holidays" NACE Corrosion 95, paper #347.
76. Orazem,M.E, "Mathematical models for cathodic protection of an underground pipeline with coating holidays. II. Case studies of parallel anode cathodic protection systems" Corrosion 53 (6), 1997, p.427.
77. Sridhar,N.; Lichtner,P.C.; Dunn,D.S., Evolution of Environment under Disbonded Coating on Cathodically Protected Pipeline – Preliminary Modeling and Experimental Studies, NACE Corrosion Conference, 1998, Paper #680.
78. N.Sridhar, D.S.Dunn, M.Seth, A.Anderko, and M.M.Lencka, "Models for Evaluating Corrosion Under Disbonded Coating on Steel Pipelines", GRI-02/0027, November 2001.
79. N.G.Thompson and K.Kelley, "Corrosion of Underground Pipe", GRI-81-0125/GTI#0380
80. J.N.Murray and H.P.Hack, "Testing Organic Architectural Coatings in ASTM Synthetic Seawater Immersion Conditions Using EIS" Corrosion 48(8), 1990, p.671
81. W.F.Fair, "Properties, Specifications, Tests and Recommendations for Coal Tar Coatings", Part 2-Cold Applied Coatings 12(12), 1956, p605t
82. Joanna Kobus, "Estimation of the Effect of the Steel Surface Condition on the Protective Properties of the Selected Coatings in Use for the Ship Equipment", Eurocorrosion 2000, London U.K.
83. Rodríguez,V.; Castaiieda,L.; Luciani,B., "Effect of Contaminants on FBE Performance" NACE Corrosion 98, Paper #612, 1998, Houston, Texas.
84. P.E.Partridge, "Effects of Phosphoric Acid Treatment on the Performance of FBE Coatings", PR247-9511, October 1997.
85. C.C.Chappelow, G.R.Cooper, C.S.Pinzino, B.LaRue, D.Rose, and S.R.Spurlin, "Effect of Substrate Contaminants on the Performance of Fusion-Bonded Epoxy Pipeline Coatings", AGA Project #. Pr-138-907, January 1992.
86. Vincent,L.D.; "Surface Preparation Standards", NACE Corrosion conference 2001, Paper # 1659, Houston, Texas.
87. J.A.Beavers, "Assessment of the Effects of Surface Preparation and Coatings on the Susceptibility of Line Pipe to Stress-Corrosion Cracking", PR186-917, February 1992.
88. Graham,J.C.; Gloskey,D.A.; Fisher,T.G.; Garling,R.A., "Temperature and Humidity Effects on the Intercoat Adhesion of Aliphatic Amine-Cured Epoxy Coatings", Materials Performance 33 (3) 1994, p.33
89. Armstrong,R.D.; Jenkins,A.T.A; Johnson,B.W., "An Investigation on the UV Breakdown of Thermoset Polyester Coatings using Impedance Spectroscopy" Corrosion Science, 37(10), 1995, p.1615.
90. T.A.Ferguson, "An Evaluation of a New Ditch Backfill Method for Use When Laying Pipelines in Rocky Terrain, GRI-97/0260/GTI 3850

91. T.J.Barlo, D.P.Werner, "Shielding Effects of Concrete and Foam External Pipeline Coatings", PR-208-631, January 1992.
92. Kellner,J.D., "Methodologies to evaluate shear strength evaluation", NACE Corrosion Conference 1996, Paper # 199, Houston, Texas.
93. Baron,J.J.; Singh,P.J., "The Results of an Evaluation of Pipeline Coatings Using New Test Methods", NACE Canadian Region Western Conference 1992, p.1.
94. J.D.Hair, PRCI project PR-003-9715, "Coating Requirements for Pipeline Installed by Horizontal Drilling and Slip Boring",
95. N.C.Saha, "Repair Coatings and Durable Paints for Gas Distribution Piping Systems", GRI-84/0055/GTI-0522
96. R.A.Gummow and S.M.Segall, "In-Situ Evaluation of Directional Drill/Bore Coating Quality", PR-262-9738, October 1998.
97. S.Jordan, "In-Situ" Detection of Disbonded Coating", AGA PR-188-606, May, 1988.
98. D.G.Stirling, "Evaluation of Coating Condition using the Elastic Wave Pig", GRI-97/0073/ GTI3329
99. M.L.Lewis, "Development of Techniques for Monitoring Pipeline Coatings with the Elastic Wave In-Line Inspection Vehicle, gti-5016/gri-00/0160
100. M.J.Frazier, "Induced AC Influence on Pipeline Corrosion and Coating Disbondment, GRI-95/0004, December 1994.
101. D.H.Pope and D.C.White, "Microbiologically Influenced Corrosion in the Natural Gas Industry, GRI 90-0237.
102. S.Papavinasam and R.W. Revie, "Coating Gap Analysis", PRCI Report # L51971.

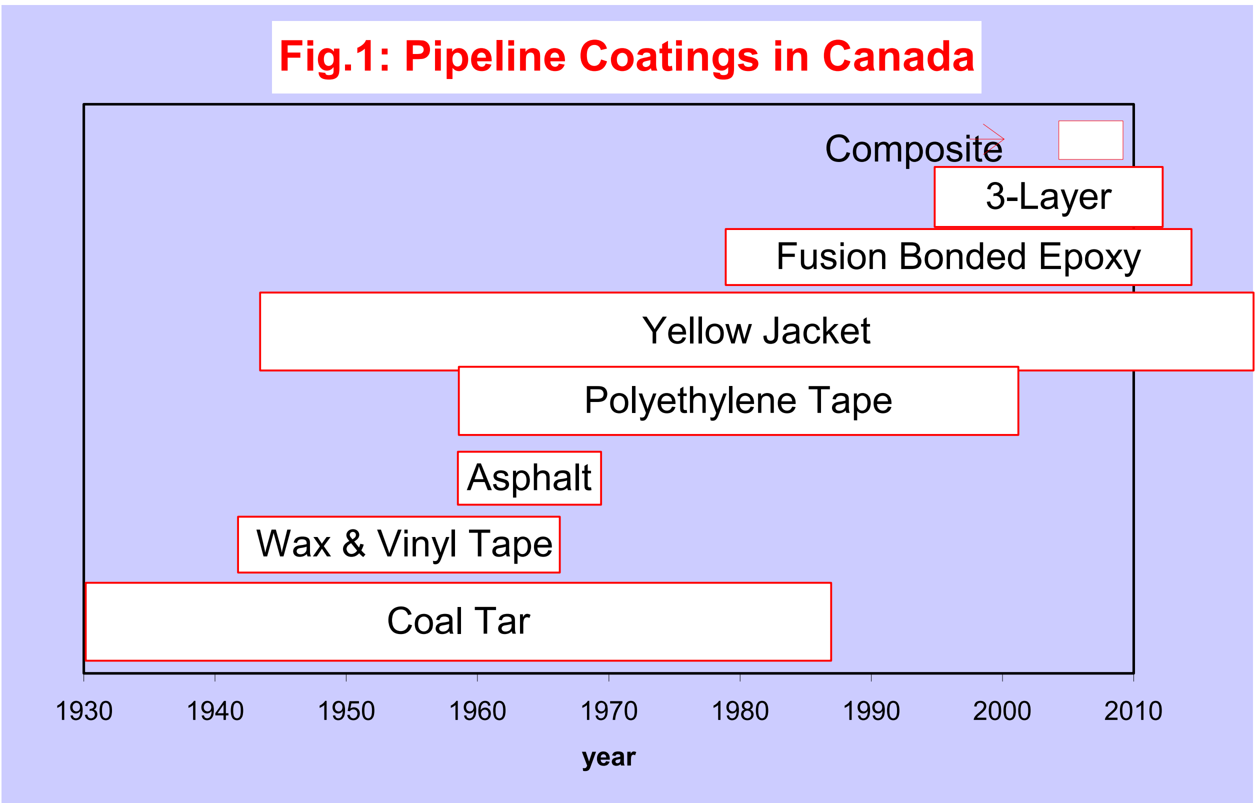
Fig.1: Pipeline Coatings in Canada
Composite
3-Layer
Fusion Bonded Epoxy
Yellow Jacket
Polyethylene Tape
Asphalt
Wax & Vinyl Tape
Coal Tar
1930
1940
1950
1960
1970
1980
1990
2000
2010
year

Table 1: Standard Laboratory Tests for Pipeline Coatings

Name of the test	Standard from	Information used to evaluate
Gel time	CSA Z.245.20.98 (Section 12.2)	Coating quality
Gel time	NACE RP0394-94 (Appendix D)	Coating quality
Moisture content - Titration	CSA Z.245.20.98 (Section 12.3)	Coating quality
Moisture content - Mass Loss	CSA Z.245.20.98 (Section 12.4)	Coating quality
Moisture content	NACE RP0394-94 (Appendix F)	Coating quality
Particle size	CSA Z.245.20.98 (Section 12.5)	Coating quality
Particle size	NACE RP0394-94	Coating quality
Density	CSA Z.245.20.98 (Section 12.6)	Coating quality
Density	NACE RP0394-94 (Appendix B)	Coating quality
Thermal characteristics	CSA Z.245.20.98 (Section 12.7)	Coating quality
Thermal analysis/characteristics	NACE RP0394-94 (Appendix E)	Coating quality
Cure cycle	NACE RP0394-94	Coating quality
Glass transition temperatures	NACE RP0394-94 (Appendix E)	Coating quality
Heat of reaction	NACE RP0394-94 (Appendix E)	Coating quality
Total volatile content	NACE RP0394-94 (Appendix G)	Coating quality
Interface contamination	CSA Z.245.20.98 (Section 12.15)	Coating quality
Porosity	CSA Z.245.20.98 (Section 12.10)	Coating quality
Porosity	ANSI/AWWA C203/97 (Section 5.3.14.4)	Coating quality
Viscosity	CSA Z245.21.98 (Section 12.1)	Coating quality
Flow	CSA Z245.21.98 (Section 12.2)	Coating quality
Cross-section porosity	NACE RP0394-94 (Appendix J)	Coating quality
Interface porosity	NACE RP0394-94 (Appendix K)	Coating quality
Interface contamination	NACE RP0394-94 (Appendix P)	Coating quality
Surface preparation	SSPC-SP6/NACE No.3	Surface preparation

Surface preparation	SSPC-SP10/NACE No.2	Surface preparation
Surface preparation	ISO 4618-3:1999	Surface Preparation - Terms and definitions for coating materials
Shelf life	NACE RP0394-94 (Appendix C)	Handling
Outdoor weathering	ASTM G 11	Handling
Water resistance (100% relative humidity)	ASTM D 2247	Handling
Flexibility	CSA Z.245.20.98 (Section 12.11)	Testing (Hydrostatic expansion)
Flexibility (2^o/PD at -18^oC or 1.5^o/PD permanent strain)	NACE RP0394-94 (Appendix K)	Testing (Hydrostatic expansion)
Bendability	ASTM G 10	Installation
Bendability (ring) - squeeze test	ASTM G 70	Installation
Cathodic disbondment	CSA Z.245.20.98 (Section 12.8)	Operation
Cathodic disbondment of strained coating	CSA Z.245.20.98 (Section 12.13)	Operation
Cathodic disbondment (24 hours or 28 days	NACE RP0394-94 (Appendix H)	Operation
Cathodic disbondment	ASTM G 8	Operation
Cathodic disbondment	ASTM G 80	Operation
Cathodic disbondment (Attached cell method)	ASTM G 95	Operation
Cathodic disbondment (Elevated temperature)	ASTM G 42	Operation
Chemical resistance	CSA Z.245.20.98 (Section 12.9)	Operation
Chemical resistance	NACE RP0394-94 (Appendix I)	Operation
Chemical resistance	ASTM G 20	Operation
Impact resistance	CSA Z.245.20.98 (Section 12.12)	Operation
Impact resistance	NACE RP0394-94 (Appendix L)	Installation
Impact resistance (Limestone drop)	ASTM G 13	Installation

Impact resistance (falling resistance)	ASTM G 14	Installation
Impact resistance (effects of rapid deformation)	ASTM D 2794	Installation
Impact	ANSI/AWWA C203/97 (Section 5.3.7)	Installation
Impact resistance	ANSI/AWWA C214-95 (Section 5.3.10)	Installation
Adhesion	CSA Z.245.20.98 (Section 12.14)	Operation
Adhesion	ASTM D 3359	Operation
Adhesion (Constant rate of peel)	CSA Z245.21.98 (Section 12.4)	Operation
Adhesion (peel by hanging mass)	CSA Z245.21.98 (Section 12.5)	Operation
Adhesion	ANSI/AWWA C203/97 (Section 5.3.13.7)	Coating quality/operation
Adhesion	ANSI/AWWA C214-95 (Section 5.3	Coating quality/operation
Peel (adhesion)	ANSI/AWWA C203/97 (Section 5.3.6 and 5.3.8)	Operation
Ageing (Heat)	CSA Z245.21.98 (Section 12.6)	Operation
Strain resistance	NACE RP0394-94 (Appendix M)	Operation
Abrasion	NACE RP0394-94 (Appendix O)	Installation/Handling
Abrasion resistance	ASTM D 968	Installation/Handling
Abrasion resistance	ASTM G 6	Installation/Handling
Hot water soak	NACE RP0394-94 (Appendix N)	Operation
Water absorption	ANSI/AWWA C214-95 (Section 5.3.4)	Operation
Water-vapour transmission	ANSI/AWWA C214-95 (Section 5.3.5)	Handling
Water penetration	ASTM G 9	Operation
Penetration resistance	ASTM G 17	Operation
Penetration	ASTM G 17 at 93^{o}C	Operation

Penetration	ANSI/AWWA C203/97 (Section 5.3.2)	Operation
Penetration	ANSI/AWWA C214-95 (Section 5.3.11)	Operation
Sag	ANSI/AWWA C203/97 (Section 5.3.4)	Operation
Pliability	ANSI/AWWA C203/97 (Section 5.3.9)	Operation
Breaking strength	ANSI/AWWA C203/97 (Section 5.3.12)	Coating quality
Softening point	ANSI/AWWA C203/97 (Section 5.3.13.4))	Coating quality
Dielectric strength	ANSI/AWWA C214-95 (Section 5.3.6)	Coating quality
Insulation resistance	ANSI/AWWA C214-95 (Section 5.3.7)	Coating quality
Tensile strength	ANSI/AWWA C214-95 (Section 5.3.8)	Coating quality
Elongation	ANSI/AWWA C214-95 (Section 5.3.9)	Coating quality
Steel pipes and fittings for buried or submerged pipe lines -- External and internal coating by bitumen or coal tar derived materials	ISO 5256:1985	General

Table 2: CEPA - Soil Type Description

Soil Type	Description	Numeric Code
Alluvium	Various textures, utilized in this classification for mountainous areas only	1
Waterways	Lakes, swamps, rivers, ditches	2
Gaciofluvial	Sandy and/or gravel textures	3
Moraine Till	Variable soil texture, variable size range of stones sand and gravel clay and silt >1m to bedrock	4
Organic	Organic over clay	5
Lacustrine	Clayey to silty fine textured soils	6
Organic	Organic over gravel	7
Rock		8
Creeks and Streams	Clay bottom (generally <5m in width)	9