APPENDIX F USE OF THREE-LAYER POLYETHYLENE COATINGS ON THE ALASKA LNG PIPELINE

3LPE Coating

Technical Support

1.0 EXECUTIVE SUMMARY

The correct selection of an external corrosion coating for a particular pipeline is critical to the long-term reliability of that pipeline. Synergistically with a properly designed/operated cathodic protection (CP) system, this provides the corrosion protection system for the design life of the pipeline. The coating represents passive protection, while the CP system is active protection.

Two coating systems were evaluated for use, both considered to be state-of-the-art in corrosion protection coating technology: fusion bonded epoxy (FBE) and three-layer Polyethylene (3LPE). Selection of 3LPE is based on the superior performance expected using this corrosion protection system on this pipeline over the long term.

The critical parameters for coating performance are adhesion to steel, resistance to physical damage and chemical degradation, high dielectric strength/barrier properties, compatibility with the CP system, and maintainability over the design life. Many other factors also must be considered, including field joint coating compatibility, application quality, etc.—these also are part of the selection process.

All pipeline coatings would suffer some physical damage during transport to the site, installation, backfilling operations, and as the line settles/moves during service. The CP system is designed to protect against corrosion at areas of coating damage. Most of the pipeline would be installed in very remote locations with rugged terrain and little pipe handling infrastructure, so a fair amount of coating damage can be expected by the time it is commissioned.

FBE, being a brittle and relatively thin coating, is known to be much more susceptible to physical damage than 3LPE. In addition to physical damage, FBE would absorb water and undergo some chemical degradation in the form of blistering disbondment. Use of FBE as the passive component for this corrosion protection system would mean a greater reliance on the active component of the system—CP. Placing more demands on monitoring and maintaining the active CP system increases the risk of a failure of the corrosion protection system.

By contrast, 3LPE represents significantly greater contribution of passive corrosion protection component and much less reliance on the active component. In remote locations, monitoring and maintenance of CP systems is not trivial. Selection of 3LPE as the superior coating system for this application is a risk-based decision, rooted in this factor.

The United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration has expressed concerns about the use of 3LPE for the Project pipelines. Among these are the possibilities of shielding CP by 3LPE, undetectable stress corrosion cracking (SCC) in shielded locations, monitoring the corrosion protection system with over-the-line and in-line inspection techniques, and an overall lack of experience operating 3LPE coated pipelines.

The same onshore pipeline cathodic protection over-the-line surveillance technique known as close-interval potential survey (CIPS) and the related over-the-line technique of direct current voltage gradient (DCVG) used effectively for FBE coatings will be effective for 3LPE as well. 3LPE disbondment defects which pose an external corrosion risk are detectable with over the line surveys. There are two possible scenarios of coating damage (discussed further in Section 6.0) that would not be detectable with over-the-line techniques, however, neither of these would not result in external corrosion.

2.0 CATHODIC PROTECTION AND DISBONDED COATINGS

3LPE pipe coating systems are in common usage globally. The system would consist of an inner layer of FBE applied to a minimum of 10 mils (250 microns). An outer layer of extrusion applied polyethylene, which is at least 118 mils (3 millimeters thick), is bonded strongly to the FBE via 6 mils (150 microns) of copolymer. ExxonMobil has extensive positive experience with 3LPE, including several major overland pipelines (e.g., Chad-Cameroon, Sakhalin 1, Papua New Guinea). All these lines utilize conventional CP in addition to 3LPE. To date none of the lines has suffered external corrosion damage.

2.1 CATHODIC PROTECTION DESCRIPTION

CP is required to protect the external steel surface of the pipeline from corrosion. CP functions by polarizing the steel electro-negatively, which thermodynamically suppresses corrosion. Polarization (shifting the electrochemical potential of the steel) occurs when electrical current ("current") is imparted on steel. Current originates at an anode(s), and by convention travels through the electrolyte (soil/water), is "picked up" by the pipeline and returns to the rectifier and/or anode through the pipeline and CP circuitry. The amount of current is necessarily minimized through the use of a high-integrity pipe coating. Thus the amount of current needed for protection is a function only of an assumed amount of coating damage exposing a minimal area of steel substrate to the soil.

2.2 CATHODIC PROTECTION CURRENT AND DISBONDED COATINGS

When a coating disbonds from its substrate yet remains intact and bonded between layers, a void or crevice exists between the disbonded coating and the underlying substrate. If the disbondment is breached, small amounts of soil and water can migrate into the crevice. Certain coating systems and associated disbondment defects limit or prevent CP polarization of the underlying steel, which creates a risk of corrosion (shielded corrosion) if corrosive species are present. However, not all disbondment events are corrosion risks. The vulnerability of a coated, cathodically protected pipeline to shielded corrosion is a function of the coating system, and the nature of the disbondment event. The amount of polarization (protection) achievable in a crevice under a disbonded coating is expressed as Ohm's law.

2.3 POLARIZATION UNDER DISBONDED COATING

Potential gradients can be viewed as "potential drops" between the anode and the targeted location (steel substrate exposed when coating is damaged). Potential drops are commonly accounted for when measuring the potential of a pipeline to verify the level of CP. Such "*IR* free" or "off" potentials are obtained by cycling CP power off, so that only the potential of the pipeline is measured. Voltage or potential drops occur whenever current passes through a resistive conductor. This phenomenon is well understood and is expressed as Ohm's law:

$$\Delta E = IR$$

Where ΔE is the change in potential or voltage drop, I is current in amps, and R is resistance in ohms.

In the aforementioned crevice, I is a function of the area of steel exposed to the electrolyte, and R is a function of the size of the crevice and the resistivity of the electrolyte. Consider the following examples:

2.3.1 Large Disbondment/Large Area of Exposed Steel Substrate

When a large area of coating disbonds, a similarly large area of steel substrate is exposed. A large area of steel would require a proportionally large amount of current (I) to achieve polarization. R would also be large given the length of a deep crevice. Hence the product of I and R in this scenario is a large potential drop. If the potential drop is large enough, CP would not be sufficient to arrest corrosion. Shielded corrosion failures of coated pipelines are best described by this scenario. Coating systems that are vulnerable to such failures are systems with lower adhesion strength that do not have a tightly adhering inner primer coating. Asphalt coatings, polyethylene tape, heat shrink sleeves with mastic adhesives, and two-layer polyolefin systems (mill applied polyolefin systems with a mastic adhesive) are examples of this type. For single-layer coating systems of this kind, the limit of polarization under disbonded coatings has been reported as 10 centimeters (Fessler, Markworth, & Parkins, 1983).

2.3.2 Variable Size Disbondment/Small Area of Exposed Steel Substrate

If the amount of exposed steel substrate under the disbonded coating is small, the amount of current required to polarize the exposed steel would be proportionally small. A deep high resistance (R) crevice can be polarized if the required current for polarization is small, (e.g., small "I" has a small potential gradient "IR" (Fessler, Markworth, & Parkins, 1983). This scenario is representative of disbondment of polyolefin systems with FBE primers (3LPE). Simple disbondment of the polyethylene (PE) layer would not shield CP if the FBE primer is intact. Further, if the PE disbonds and a holiday exists in the FBE primer, polarization of the steel even in a deep crevice is probable given the very small I required to polarize the small area of steel (represented by the holiday).

Beyond ohmic voltage drop, minor influences on polarization behavior in a crevice are the conductivity and chemical composition of the crevice electrolyte. Over time, polarization alters the electrolyte pH. These changes promote corrosion mitigation by raising the pH and conductivity (Fessler, Markworth, & Parkins, 1983) (Gan, Sun, Sabde & Chin, 1994) (Li, Kim, Kho & Kang, 2004) (Jack, Van Boven, Wilmott, Sutherby & Worthingham, 1994).

Modern 3LPE systems as prescribed by Company and Industry Practices (ExxonMobil Global Practice 56-02-04) (CSA Z245.20) (ISO 21809-1) require adhesion strengths between the PE and FBE primer that exceed soil stresses. By contrast, single- or dual-layer PE systems adhered by mastic, and absent an epoxy primer, exhibit much lower adhesion strength due to the inherent limited strength of mastics. Periodic production peel adhesion testing is required by Company and Industry practice.

2.4 SUMMARY

3LPE pipe coatings are highly resistant to failures that could result in shielded corrosion. The resistance to shielded corrosion is a consequence of the nature of polarization in crevices, and the superior adhesion of properties of the coating system. This conclusion is supported by theoretical and experimental literature. Further the absence of reported 3LPE coated pipeline failures resulting from external corrosion or SCC is consistent with this conclusion.

2.5 REFERENCES

1. Fessler, R.R.; Markworth, A.J.; Parkins, R.N. “Cathodic Protection Levels Under Disbonded Coatings” Corrosion, Vol. 39 No. 1 January 1983

2. Gan, F; Sun, W-Z; Sabde, G.; Chin, T-D; “Cathodic Protection to Mitigate External Corrosion of Underground Steel Pipe Beneath Disbonded Coatings” Corrosion, October 1994

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4. Jack, T.R.; Van Boven, G; Wilmott, M.; Sutherby, R.L.; Worthingham, R.G “Cathodic Protection Potential Penetration Under Disbonded Pipeline Coating” Materials Performance Aug 1994,

5. ExxonMobil Global Practice 56-02-04, Three Layer Polyethylene and Polypropylene Pipeline Coatings

6. CSA Z245.20, Plant Applied External Coatings for Steel Pipe

7. ISO 21809-1, Petroleum and natural gas industries — External coatings for buried or submerged pipelines used in pipeline transportation systems, Part 1: Polyolefin coatings (3-layer PE and 3-layer PP)

3.0 SHIELDING AND COATING TYPE

CP shielding—the prevention or diversion of current from its intended path—has been associated with certain types of coating systems. The possibility for shielding cannot be directly measured, assessed, or even estimated by measuring the electrical properties through an intact coating film. Presently, a National Association of Corrosion Engineers (NACE) Task Group, TG523, is presently writing a state of the art report entitled 'Consequences of Coating Failures as Related to Interaction with Cathodic Protection.' This report addresses the failure modes of various coating systems and their effects on cathodic protection effectiveness.

As covered by NACE SP0185, a barrier coating by definition restricts (or shields) the metallic pipeline surfaces from contact with water, oxygen, and/or cathode depolarizers. Those that allow water to penetrate, such as FBE, would be more conductive with respect to the flow of protective CP current.

Inherent to all high performance pipeline coating systems is excellent adhesion to the pipe surface. Intact, strongly adhered coatings prevent water from coming into contact with the surface, and provided they maintain their barrier properties, would maintain a high electrical resistance.

When the bond is compromised due to factors such as poor surface preparation of the steel, or chemical degradation of the coating, the coating disbonds, creating a situation where moisture can enter between the pipe and the coating at locations where the coating has been compromised, i.e., the barrier has been breached. At these locations, the elements for a corrosion cell—anode, cathode, metallic path, electrolytic path—are present. For coatings that allow water to permeate, CP current may flow through the coating to the pipe surface and polarize the surface, preventing the corrosion reaction. For those coatings that do not allow for water permeation, an unlikely condition can exist where there is a layer of moisture between the pipe and the intact coating, but adequate protective current cannot flow to polarize the disbonded site to an adequate level. This then describes a CP shielding coating.

FBE coatings are held up as the standard for non-shielding behavior, and there have been no reported instances of FBE-coated pipelines displaying shielding behavior. It is incorrectly assumed that FBE coatings are transparent to CP current, that they are not capable of shielding because electrolyte passes through them. PRCI research (PR-186-9810) has proven that intact FBE coatings would NOT pass current,

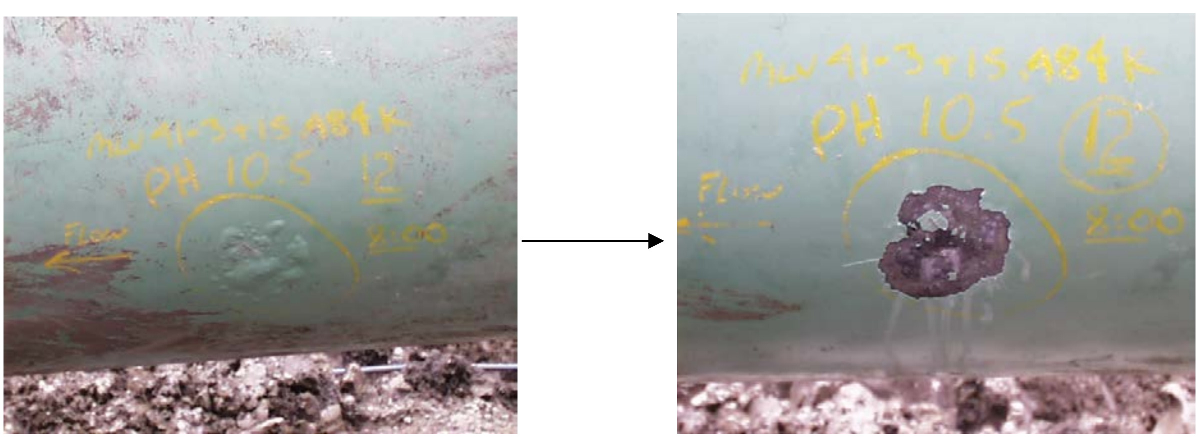
Figure 1: Corrosion product observed on the backside of a freestanding FBE sheet (from PRCI report PR-186-9810)

so they can shield CP—corrosion was observed under FBE in that investigation (Figure 1). This is consistent with the function of a good pipeline coating, which is to have high electrical resistance and promote electrical isolation. In fact, if an intact FBE coating allowed the passage of current directly to steel, the demand on the CP system would be unmanageable, since any wet area of the pipe would be drawing current through the coating. This does not happen in operating pipelines.

So why is it that FBE is thought to be "transparent" to CP? The need for such transparency is only applicable if a coating has disbonded; as described above, intact coatings do not allow passage of current. Thus, the manner in which a coating disbonds/fails is essential to understand the possibility of adequate CP protecting the bare steel.

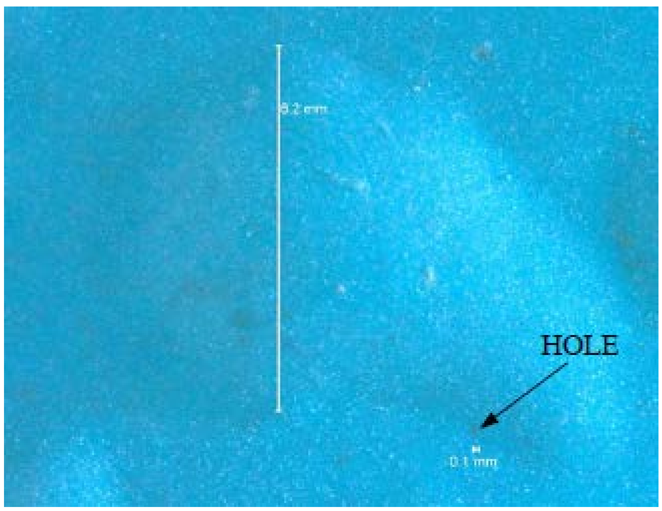
Disbondments of FBE in the pipeline industry most often take the form of blisters, but generally it has been observed that under these blisters is a high pH solution and no corrosion or SCC (Figure 2), confirmation that the CP system has been able to permeate the blister.

Figure 2: Blistered FBE coating on an operating pipeline—after the blisters are removed, no corrosion on the steel and a high pH solution (10.5), indicating CP current has been effective



Further PRCI research (PRCI Report PR-186-4307), consistent with what has been observed in the pipeline industry, has shown that FBE coatings often fail by blistering, and that under the blisters a high pH fluid formed, consistent with CP passage. Direct measurements of current showed that current flow (initially zero) increased at some point in time, likely during initiation of the blisters. The electrochemical impedance—a measure of the frequency dependent electrical resistance—dropped precipitously when coatings blistered. Both the current flow and the impedance drop were due to the creation of microdefects in the FBE coating (Figure 3), not because of simple water absorption.

Figure 3: Microdefect at edge of FBE blister (PRCI report PR-186-4307)



It is the manner in which a coating fails (not the monolithic properties of the freestanding coating) that determine the tendency of a coating to shield CP. As discussed previously, when FBE disbonds, its brittleness results in microcracking (Figures 4 and 5). This provides a direct path for current to the steel from the CP system, and is why FBE coatings are considered CP friendly.

Figure 4: FBE, blistered from immersion in groundwater (CP effective, no corrosion)

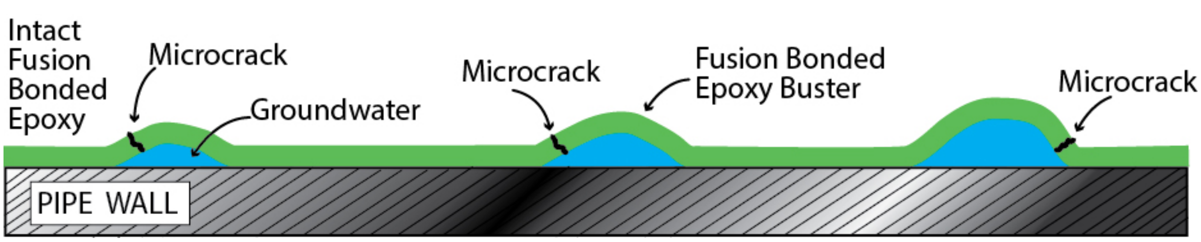
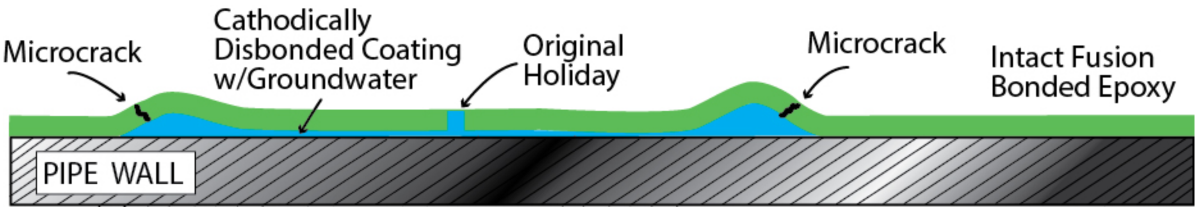


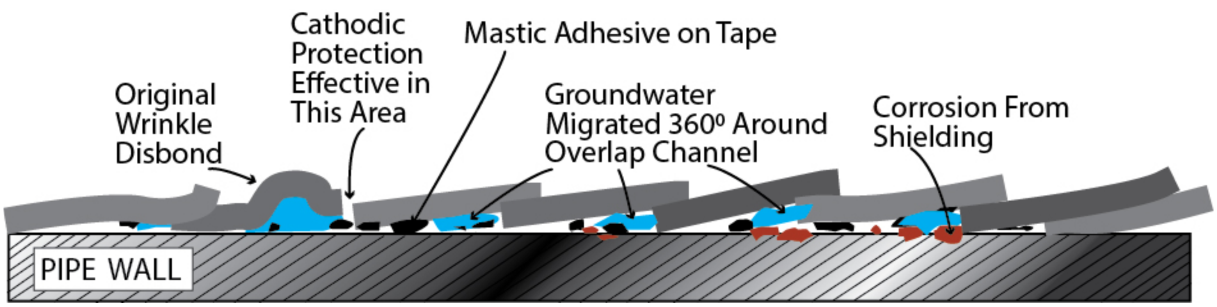
Figure 5: FBE, blistered from cathodic disbondment at a holiday (CP effective, no corrosion)



Coatings that are not considered CP friendly include tape wraps and heat shrink sleeves. A major contributor to these failures are that the adhesives used are soft, discontinuous mastics with poor adhesion to steel. Soil stress acting on the outer wrap causes wrinkling of the tape (Figure 6), which allows water ingress. Near the ingress point, cathodic protection can be effective, but along the overlap region, where tenting of the polyolefin tape occurs, water can migrate 360 degrees around the tented channel and CP shielding is possible (Figure 7), due to the large surface area of steel only marginally coated with mastic adhesive.

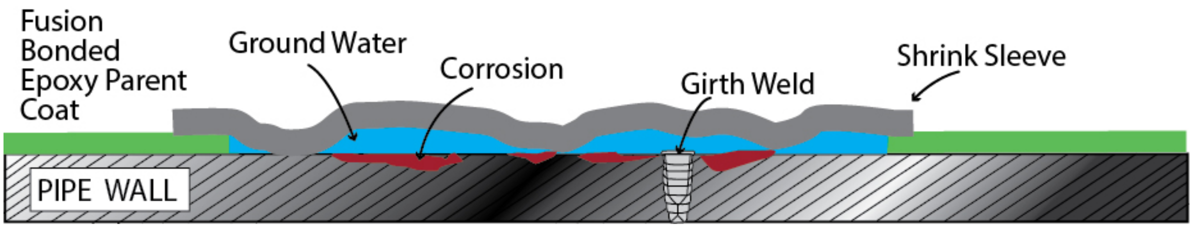
Figure 6: Tape-wrap coated pipeline displaying wrinkling from soil stress

Figure 7: Tape wrap wrinkle from soil stress, shielding possible



Heat shrink sleeves also fail by the action of soil stress (Figure 8). While heat shrink sleeves lack the numerous overlaps that a tape wrap displays, their adhesion is similarly poor and often worse, resulting from uneven heating of the sleeve combined with a lack of inspection capability on an installed sleeve.

Figure 8: Heat shrink sleeve girth weld coating, disbonded, shielding possible



Three-layer polyethylene coatings have primers (FBE) with very high adhesive strength, not affected by soil stress. Therefore, the only entry point for groundwater is at a site of mechanical damage or where it is joined to the girth weld coating. Disbondment of the PE topcoat results in minimal exposed steel surface—the exposed steel surface can be easily polarized by the CP system because of the small amount of current required for a small disbondment. These scenarios are illustrated in Figures 9 and 10.

Figure 9: Three-layer polyethylene, disbonded from mechanical damage, minimal steel surface exposed, CP effective, no corrosion

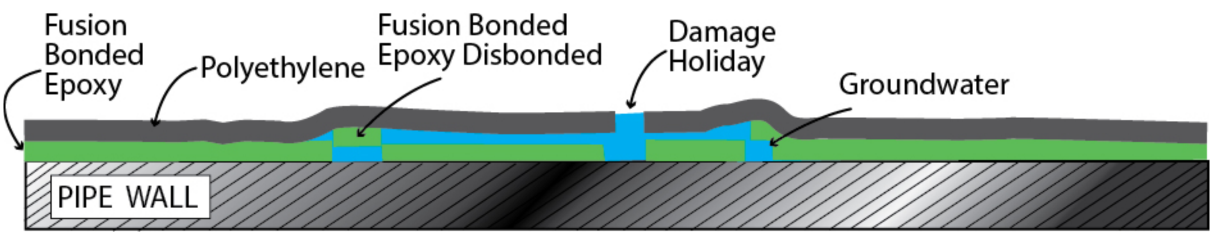
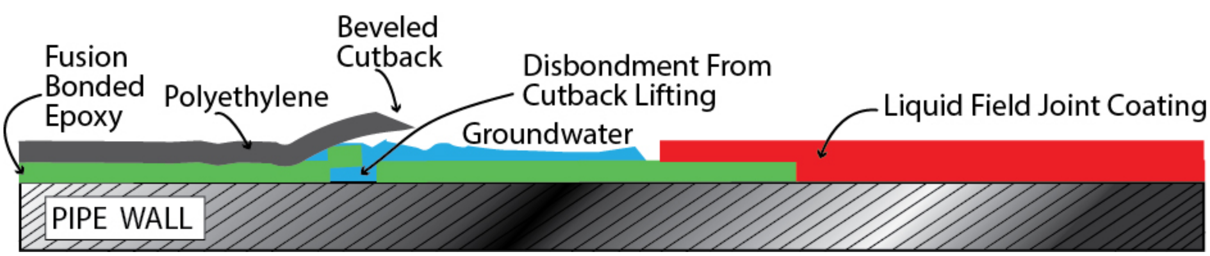
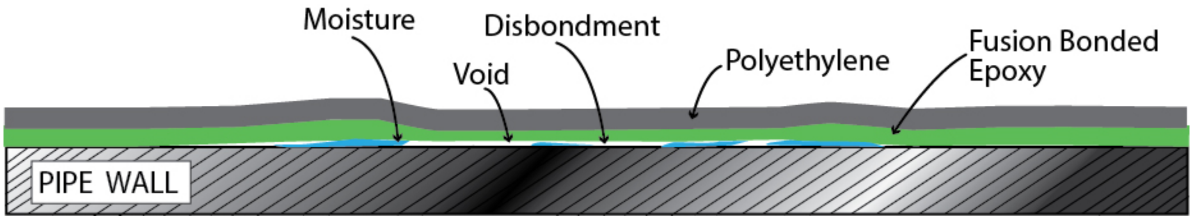


Figure 10: Three-layer polyethylene, disbonded at cutback near girth weld, CP effective at holiday, minimal CP current needed to protect small FBE holiday



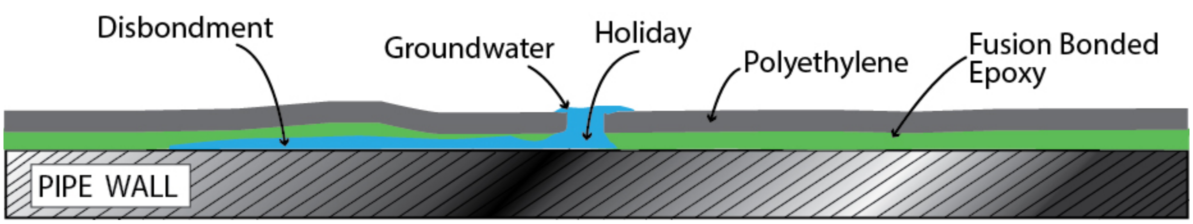
First generation 3LPE coatings sometimes disbonded in large sheets (Figure 11), but in all instances minimal corrosion was found under the disbondments (see section 8.0 Assessment of Historical Pipeline Failures). Areas under the disbondments may be dry, or may have some water that migrated laterally through the FBE primer, but the corrosion reaction in this case is self-limiting (due to saturation of the groundwater with iron ions from initial corrosion) and the groundwater is not replenished during wet/dry cycles because of the excellent barrier properties of the polyethylene.

Figure 11: Three-layer polyethylene, disbonded from poor initial adhesion, minimal to no corrosion due to barrier properties of coating, no groundwater replenishment



Theoretically, in the case of a holiday in a large area of disbondment (Figure 12), shielded corrosion could occur. However, significant corrosion due to shielding has not been widely reported even for the cases where 3LPE has disbonded in large sheets. One possible explanation for this is that it is due to the configuration of the coating after adhesion is lost. Because 3LPE has a higher thermal expansion coefficient than steel, it shrinks tightly onto the pipe upon cooling from the application temperature. Because of this tight fit and the relatively thick coating, wrinkling under the influence of soil stress as with older tape wrap coatings (Figure 6) is not seen with 3LPE. Thus, in the case of a loss of adhesion, the crevice between the 3LPE and the pipe would be tight. CP current would reach only a limited distance into the tight crevice. However, the tight crevice may also restrict the flow of fluid through the crevice such that a corrosion reaction cannot be sustained far into the crevice as oxygen depletion and pH increases occur in the crevice. This mechanism, which has been described by Gan, et al., potentially explains the lack of pipeline failures or widely reported corrosion issues for historical cases of disbondment of 3LPE coatings. Nevertheless, ensuring good adhesion of the 3LPE coating to the pipe is the primary means of ensuring that corrosion under a disbonded coating as pictured in Figure 12 does not occur. As discussed in the section 8.0 Assessment of Historical Pipeline Failures, this type of disbondment is no longer expected in modern 3LPE coatings because of improvements in the coating products and application processes.

Figure 12: Three-layer polyethylene, disbonded from poor initial adhesion with a holiday present, CP current reaches area near holiday. Corrosion deep in the crevice may be limited by barrier properties of coating and limited rate of groundwater replenishment when crevice is tight.



3.1 REFERENCES

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2. PRCI Report PR-186-9810, "Performance of Blistered FBE Coated Pipe", July 2000.

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4. Gan, F; Sun, W-Z; Sabde, G.; Chin, T-D; "Cathodic Protection to Mitigate External Corrosion of Underground Steel Pipe Beneath Disbonded Coatings" Corrosion, October 1994

4.0 SCC ON COATED PIPELINES

Underground external SCC initiates on the external pipeline surface and can grow in both depth and surface directions. The environment causing SCC typically includes a relatively small volume of fluid trapped between a disbonded coating and the pipe surface. SCC can only occur where coating is disbonded or damaged and where inadequate CP is available at the pipe surface. Inadequate CP can be due to inherent shielding properties of the coating or to external factors that affect CP effectiveness. Shielding is defined as preventing or diverting CP current from its intended path and is discussed in the next section.

If either the coating remains bonded to the pipe surface or adequate CP potentials (per NACE SP0169) are achieved at the pipe surface anywhere the coating is not intact, SCC does not occur. Underground external SCC would not occur if the pipeline has a tightly adhered, high performance coating.

High pH SCC is associated with a narrow potential range (-600 to -850 mV $Cu/CuSO_4$ off potential) in the presence of a carbonate/bicarbonate environment in alkaline conditions at the pipe surface with pH higher than 9.3. Documented cases of high pH SCC occur at temperatures >100 °F. It is found most commonly on pipes coated with field-applied coal tar enamel, tape or asphalt, or in similar factory-applied coatings where the surface preparation was less than ideal.

Near-neutral pH SCC is associated with conditions where the protective coating of the pipe disbonds and the coating prevents the cathodic current from reaching the pipe surface. It can occur beneath a mechanically failed coating in the absence of adequate cathodic protection current, or when the failed coating acts to shield the steel surface from cathodic current while allowing the ingress and trapping of an electrolyte against the surface. The corrosion conditions that develop below the disbonded coating result in an environment with a pH of between 5.5 and about 8.

SCC has not occurred on pipelines coated with FBE or 3LPE. One major contributor to this is that both of these coating systems are applied to grit blasted surfaces, which have a number of beneficial effects:

- Generally improves resistance of the coatings to disbonding as a result of the anchor pattern created;
- Removes the mill scale, which results in an ability for CP to move the pipe-to-soil potential more readily out of the critical potential range for cracking;
- Introduces a deformed layer, which distorts the path for cracking; and
- Introduces compressive stresses in the surface layer.

API RP1176 confirms the beneficial effects of residual compressive stress induced at the surface by the coating surface prep process. (API RP1176, sec 6.2.1.3). Open literature publications, in which 3LPE systems were found to have disbonded, noted that SCC was not found. One such investigation (IPB1357_05, Addressing Stress Corrosion Cracking on Multilayer Pipeline Coating Systems), noted that "Within the pipeline industry, especially in Canada, it is generally accepted that these residual compressive stresses minimize the formation of pipeline SCC because a localized stress riser is necessary for SCC to initiate. On pipe surfaces that are not grit blasted, stress risers are found on areas with higher than normal residual stresses relative to the remainder of the pipeline. If SCC is to form, a localized stress riser such as external corrosion, mill scale, dents, scabs, gouges or short- and long-term operating stresses induced from system operating irregularities must be present. Once the thin outer layer of material that is in compression is breached by a stress riser, cracking may initiate in the steel, which experiences slightly greater tensile forces immediately beneath the surface layer.

4.1 REFERENCES

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2. Scott Hardy, James Marr, Martyn Willmot, David Norman, Ashish Khera, “Addressing Stress Corrosion Cracking on Multilayer Pipeline Coating Systems”, IBP1357_05, Rio Pipeline 2005 Conference.

3. Bill Gu, Richard Kanai, Ming Gao, Wayne Feil “Development of SCC Susceptibility Model Using a Decision Tree Approach” Corrosion 2005, NACE-05479. NACE International; 2005.

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5.0 QA/QC TESTING OF 3LPE COATINGS

It is widely recognized in the coating industry that the relative performance of any coating system would depend as much on the surface preparation and application quality as on the selection of the system itself. For plant-applied FBE and three-layer coatings, CSA Z245.21-14 describes a long list of qualification procedures.

QC performed on plant-applied coatings on specified frequencies, typically once per shift, ensure that the coating process remains consistent throughout the entire job. Tests that check surface cleanliness and anchor pattern provide an assurance that the most common cause of poor adhesion—an improperly prepared surface—is avoided. Post-application tests (thickness, cathodic disbondment and water soak) provide assurance that the entire system was applied and cured to the specification.

ExxonMobil Global Practice 56-02-04 lists a set of specific tests required, using procedures from CSA Z245.20, NACE SP0394, and ISO 21809-1, the three most widely accepted pipeline coating standards in the industry. Tests included are the following:

Tests that verify the coating materials received meet the requirements:

1. FBE powder properties
2. Co-polymer adhesive properties
3. PE polymer properties
4. Thermal aging of PE material

Tests that verify the steel surface would be properly prepared:

1. Salt contamination
2. Residual magnetism
3. Abrasive cleanliness
4. Pipe surface temperature (prior to blasting)
5. Phosphoric acid rinse properties
6. Rinse water properties
7. Anchor pattern
8. Coating application temperature

Tests that verify the applied system meets the requirements:

1. Dry film thickness
2. Holiday test
3. Cathodic Disbondment
4. Peel Adhesion
5. Flexibility
6. Hot Water Soak

Discussions with applicators and end-users regarding coating failures consistently point to either the lack of adequate quality assurance/quality control procedures or to a failure to enforce these procedures during coating application. This is consistent with the discussions in the publications on field performance in section 8. Implementation of a robust quality plan with documentation and inspection is the way that successful coating jobs are completed and that long-term reliability is enabled.

5.1 REFERENCES

1. CSA Z245.21-14, Plant-applied external polyethylene coating for steel pipe

2. NACE SP0394-2013, Application, Performance, and Quality Control of Plant-Applied Single-Layer Fusion-Bonded Epoxy External Pipe Coating

3. ISO 21809, Petroleum and Natural Gas Industries - External Coatings for Buried or Submerged Pipelines used in Pipeline Transportation Systems - Part 1: Polyolefin Coatings (3-Layer PE and 3-Layer PP)

4. ExxonMobil Global Practice 56-02-04, Three-Layer Polyethylene and Polypropylene Pipeline Coatings.

6.0 UTILITY OF OVER-THE-LINE SURVEILLANCE TECHNIQUES ON 3LPE COATED PIPELINES

Onshore pipeline CP effectiveness is verified by performing an over-the-line surveillance technique known as close-interval potential survey (CIPS). The CIPS method involves measuring the potential of the pipeline along its length at intervals of the walking stride of a person. Coating defects that expose the external steel surface to the soil (electrolyte) allow for CP current "pick up" at the local area of exposure. Fundamentally, current passing through a medium generates a potential gradient. This local gradient is detectable by a CIPS and the related over-the-line technique of direct current voltage gradient (DCVG). The same over-the-line techniques used for FBE coatings are effective for 3LPE. 3LPE disbondment defects that pose an external corrosion risk are detectable with over-the-line surveys.

There are two possible scenarios of coating damage that would not be detectable with over-the-line techniques; however, neither of these would result in external corrosion. The first is an interlayer disbondment between the polyethylene and FBE layers where the FBE layer remains intact. In this case no external corrosion occurs because the FBE protects the underlying steel surface. The second possible scenario is a disbondment of both the polyethylene and FBE from the steel, but no break in the polyethylene layer. Because the polyethylene layer remains intact, and defect free, a corrosion risk does not exist.

Any coating disbondment defect that exposes the steel surface to the electrolyte is detectable with CIPS, even if it prevents some part of the region under the disbondment from being polarized (shielding). In other words, if there is steel surface is exposed, CP current would be detected regardless of whether the current is sufficient for adequate protection against external corrosion (Lagos, Magana, Lopez, & Martinez, 2010)1). However, over-the-line techniques can not characterize the extent of coating disbondment away from a holiday and whether shielded corrosion is occurring. For this reason, the data from over-the-line techniques must be integrated with ILI data that detects external corrosion (e.g., Magnetic Flux Leakage) to identify any potential sites of shielded corrosion.

Company experience with long distance onshore 3LPO-coated pipelines—in Chad-Cameroon, Papua New Guinea, and Sakhalin Island— has been that it takes very little current to polarize these pipelines because of the high integrity of this coating system. Aboveground survey methods are particularly effective in locating damage due to the fact that low potential readings are rare outliers in modern 3LPO coated pipelines.

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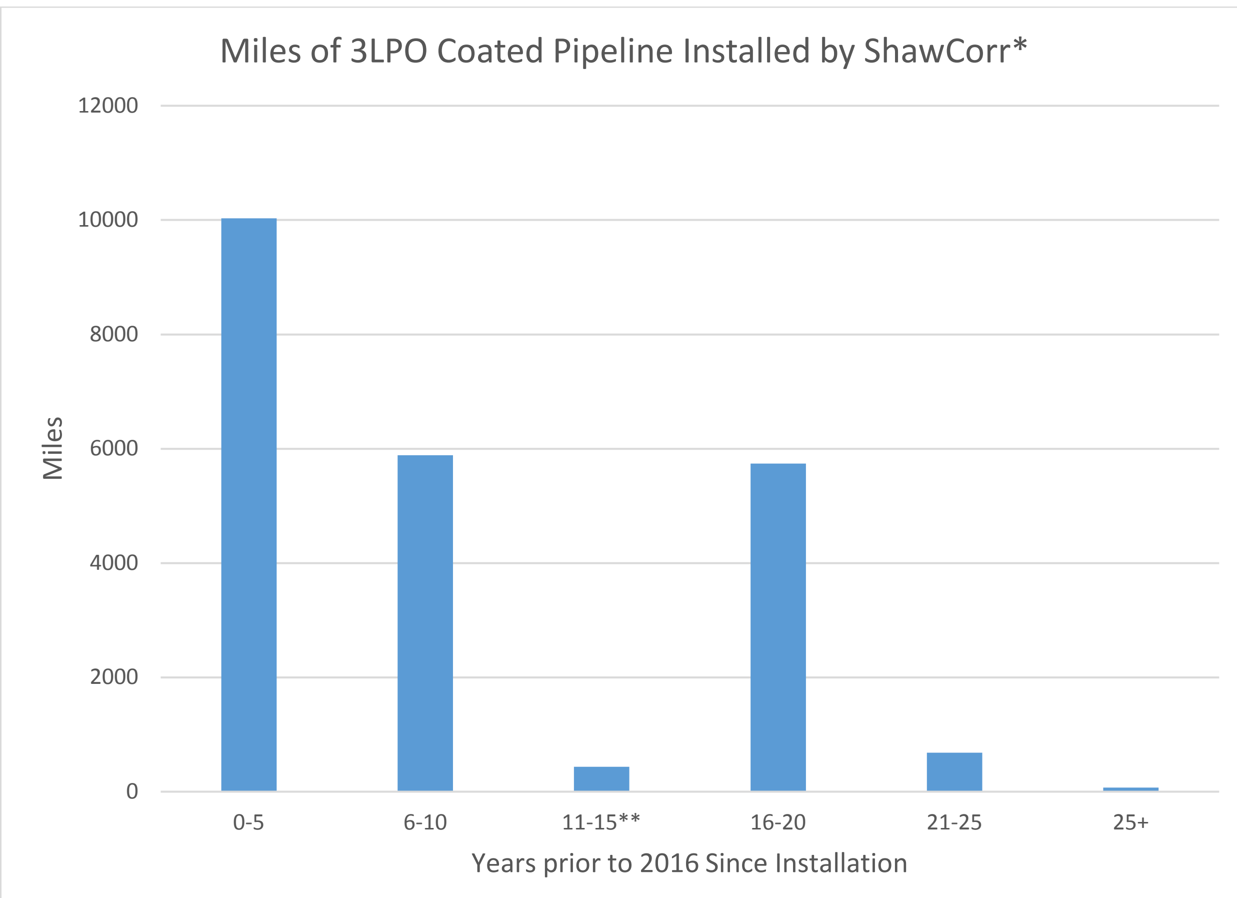
7.0 HISTORICAL USAGE OF THREE-LAYER POLYOLEFIN (3LPO) PIPE

ShawCorr, the largest applicator of pipeline coatings in the industry, surveyed all of its application plants worldwide to gather information on pipe coated with 3LPO since the first application in 1985. The improvements in the coating powders and application procedures, as well as wider acceptance in the industry, is illustrated by Figure 13. The amount of 3LPE coated pipe supplied has nearly doubled in the in the past 10 years. This is in no small part due to the end-user satisfaction with the long-term reliability of 3LPE coated pipelines from more than 20 years ago.

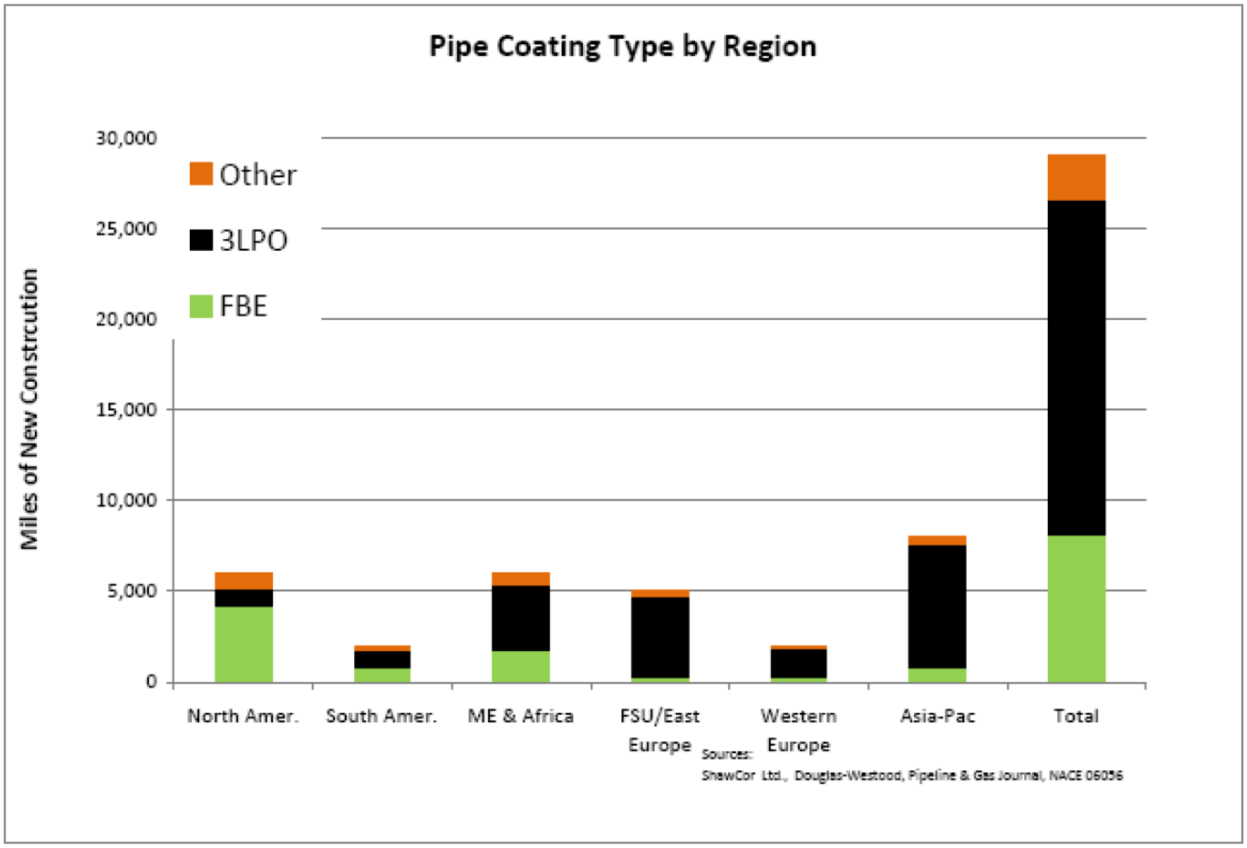
Figure 14 (Buchanan, 2013), shows that 3LPO are the most commonly selected system in the world, even though their use in North America is not as high as Europe, and Asia Pacific. Many thousands of miles have been installed, including significant mileage with fewer than 20 years in service. Despite this widespread usage, there have been no instances of SCC reported (see Section 4.0 for more details).

Figure 13: Three-layer polyethylene pipeline coating length applied by ShawCorr



*ShawCorr has approximately 50 percent of the market share for 3LPO coatings; 3LPO coatings include both three-layer Polyethylene and three-layer Polypropylene coatings
**Data set for 11–15-year usage incomplete

Figure 14: Global Coatings Market Share by Region (Buchanan, 2013).



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8.0 ASSESSMENT OF HISTORICAL PIPELINE FAILURES DUE TO EXTERNAL CORROSION

A literature review was performed to identify any known pipeline failures due to disbondment of 3LPE. The ExxonMobil Pipeline Company has been cataloging publically available pipeline failures from the past 30 years and has provided access to its extensive database. Within this database, 28 instances of pipeline failure due to external corrosion were identified. These failures include both wall loss and SCC losses. The cases were all due to disbondment of polyethylene tape, asphalt enamel, or coal tar coatings. As discussed in Section 2.0, these coatings are predisposed to shielding CP due to their tendency to disbond cleanly from steel and form long crevices. The full list of cases considered in this review follows. Further review of these 28 instances reveal that none of the recorded failures involved the disbondment of 3LPE coating.

TABLE 1

Pipeline Failures Due to External Corrosion

Failure	Location	Year of Failure	Cause	Coating	Report
Texas Eastern Gas Pipeline Company Ruptures and Fires at Lancaster, KY	Lancaster KY	1986	External (Corrosion or SCC)	No notes on coating, but predates 3LPE	National Transportation Safety Board Report PAR-87/01
Mersey Estuary Pipeline Spill	Mersey Estuary, England	1989	External (Corrosion or SCC)	No notes on coating, but predates 3LPE	Peter M. Taylor (1991) A Pipeline Spill into the Mersey Estuary, England. International Oil Spill Conference Proceedings: March 1991, Vol. 1991, No. 1, pp. 299-303.
Rainbow Pipeline Company Incidents	Utikuma station, Alberta, Canada	1993	External (Corrosion or SCC)	Polyethylene Tape	Ravi Krishnamurthy (2000) Liquid Pipeline Stress Corrosion Cracking. International Pipeline Conference: 2000, Vol. 2, pp 1439-1449
Jet Fuel Pipeline Leak, Terminal 2, Pearson International Fuel Facilities Corp	Mississauga, Ontario	1994	External (Corrosion or SCC)	No notes on coating, but predates 3LPE	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P94H0004
Foothills Pipe Lines	Maple Creek, Saskatchewan	1994	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P94H0003
TransCanada Pipelines Limited NG Pipeline Rupture	Latchford, Ontario	1994	External (Corrosion or SCC)	Asphalt Enamel	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P94H0036
Natural Gas Pipeline Ruptures, TransCanada	Rapid City, Manitoba	1995	External (Corrosion or SCC)	Asphalt Enamel, Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P95H0036

TABLE 1

Pipeline Failures Due to External Corrosion

Failure	**Location**	**Year of Failure**	**Cause**	**Coating**	**Report**
Crude Oil Pipeline Rupture, Interprovincial Pipe Line Inc.	Glenavon, Saskatchewan	1996	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P96H0008
Koch Pipeline Company Rupture and Release of Butane	Lively, TX	1996	External (Corrosion or SCC)	Polyolefin Tape	National Transportation Safety Board Report PAR-98/02/SUM
Natural Gas Pipeline Ruptures, TransCanada	Cabri, Saskatchewan	1997	External (Corrosion or SCC)	Asphalt Enamel	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P97H0063
Hazardous LP Products Pipeline Rupture, Colonial Pipeline Co.	Knoxville, TN	1999	External (Corrosion or SCC)	Asphalt Enamel	National Transportation Safety Board Pipeline Accident Brief, Accident Number DCA99-MP005, PAB-01/01
Crude Oil Pipeline Rupture, Enbridge Pipelines	Regina, Saskatchewan	1999	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P99H0021
Crude Oil Pipeline Rupture, Enbridge Pipelines	Hardisty, Alberta	2001	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P01H0004
Crude Oil Pipeline Rupture, Enbridge Pipelines	Binbrook, Ontario	2001	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P01H0049
Natural Gas Pipeline Rupture, TransCanada Pipelines	Brookdale, Manitoba	2002	External (Corrosion or SCC)	Asphalt Enamel	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P02H0017
Varanus Island Sales Gas Pipeline Failure	Varanus Island, Australia	2008	External (Corrosion or SCC)	Asphalt Enamel	Government of Western Australia Offshore Petroleum Safety Regulation Varanus Island Incident Investigation
Transco Appomattox Pipeline Failure	Appomattox, VA	2008	External (Corrosion or SCC)	Coal tar enamel	US Department of Transportation Office of Public Affairs, DOT 119-09
Y Pad Gas Lift Line Failure	Greater Prudhoe Bay	2008	External (Corrosion or SCC)	Coating not noted; Lack of coating identified as problem	Safety Sharing the Experience Investigation Summary, 2008-IR-2798982
Natural Gas Pipeline Rupture, TransCanada Pipelines	Englehart, Ontario	2009	External (Corrosion or SCC)	Polyethylene Tape	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P09H0074

TABLE 1

Pipeline Failures Due to External Corrosion

Failure	**Location**	**Year of Failure**	**Cause**	**Coating**	**Report**
Williams (Transco) External MIC Failure	Kingsville, TX	2010	External (Corrosion or SCC)	Coal tar enamel	Failure Investigation Report-Williams (Transco) Corrosion Failure
Natural Gas Pipeline Rupture, TransCanada Pipelines	Beardmore, Ontario	2011	External (Corrosion or SCC)	Asphalt enamel	Transportation Safety Board of Canada Commodity Pipeline Occurrence Report Number P11H0011
Shell Cologne Refinery	Cologne	2012	External (Corrosion or SCC)	Asphalt enamel	Ministerium für Klimaschutz, Umwelt, Landwirtschaft, Natur- und Verbraucherschutzdes Landes Nordrhein-Westfalen Der Minister (Ministry for Climate Protection, Environment, Agriculture, Conservation of North Rhine) Report 16/1722
Juhi Pipeline Leak	Fiji	2012	External (Corrosion or SCC)	Fiberglass wrap	Juhi Pipeline Leak Incident Report prepared by Sirilo Samei
Majuro Airport Leak	Marshall Islands	2012	External (Corrosion or SCC)	Unidentified coating mechanically damaged in installation	Internal ExxonMobil Report
Hammond Terminal Mogas Leak	Indiana	2013	External (Corrosion or SCC)	Unidentified wrapped coating	Internal ExxonMobil Report
Plains All American Pipeline Failure	Goleta, CA	2015	External (Corrosion or SCC)	Coal tar enamel	US Department of Transportation Pipeline and Hazardous Materials Safety Administration Failure Investigation Report May 2016
EAPL LFD700 Pipeline Failure	Angola	2015	External (Corrosion or SCC)	Coal tar enamel	Internal ExxonMobil Report

As with any technology, 3LPE has benefited from iterative improvement over the past 30 years. The earliest versions of FBE primers were applied very thin (2 mils) and were the same products sold as standalone FBE coating. Argent and Norman (2005) have identified early application parameters that have since been improved that resulted in sub-optimum application of FBE to the steel surface. The high temperature needed for application and cure were not compatible with the intermediate temperature required to apply the copolymer adhesive and polyolefin topcoat, and made the pipe difficult to effectively water-cool in a continuous plant operation. These FBE powders were therefore applied at a lower temperature that enabled cure but did not allow for proper flow and wetting into the anchor pattern of the steel, and the adhesion suffered. This application error can explain some of the large disbondments observed in early 3LPE systems. As FBE powders were formulated specifically for 3LPE systems low-temperature application, Thompson and Saithala noted that second and third generation coatings of 3LPE have eliminated many of the application and adhesion problems the first generations of 3LPE experienced mentioned above.

Some early uses of 3LPE have reported coatings failures where the 3LPE disbonds from the steel surface. However, none of the literature found recorded instances of pipeline failures due to 3LPE disbondment. The available literature on 3LPE disbondment, listed below, have common themes regarding both the condition of the pipelines where 3LPE coating was found disbonded as well as improvements to prevent occurrences of disbonded coatings in future uses.

Hardy, Haimbl, Melot (2009), Nazarbeygi, Moosavi, and Tandon all have reported on instances where earlier generations of 3LPE was found to be largely disbonded on pipelines upon excavation. In each of their studies, they reported finding superficial or no corrosion under the disbonded 3LPE. Moosavi reported finding corrosion under field joints where different coatings were utilized. One instance of corrosion under 3LPE was reported by Lagos. The disbonded coating was detected using DCVG and CIS. These reports highlight that in the case of disbondment, corrosion often does not occur.

Of utmost importance from these reports is the highlighted improvements that have been identified to reduce the likelihood of disbondment in more recently applied coatings. These early cases of disbondment occurred with FBE disbonding from the steel substrate. Several of the literature sources below have identified causes for this disbondment and ways to prevent it that are now commonly implemented when using 3LPE. Argent and Norman (2005, 2006, and 2007), Lagos, Tandon, and Nazarbeygi have all highlighted effective surface preparation and QC as effective methods to reduce the likelihood of disbondment between the FBE and steel substrate.

Lastly, multiple studies have explored whether SCC has been a problem in 3LPE systems. Hardy reports of an excavation of 13 pipelines built from 1987–1996 and found no evidence of SCC. He notes the effectiveness of grit blasting on the pipelines before coating application to impart compressive strains that restrict the formation of SCC. From an extensive review of both public reports on pipeline failures and the literature review regarding 3LPE, there have been no findings of any instance of SCC due to disbondment of 3LPE coatings.

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9.0 PRIVATE DISCUSSIONS WITH PIPELINE OPERATORS

Several operators that have significant experience with 3LPE coating systems were contacted to discuss their operating history with this coating system. Some of the 3LPE systems referenced below are the HPCC (high performance composite coating) and HPPC (high performance powder coating), different acronyms for a particular type of 3LPE produced only in Canada by ShawCor.

Gasunie

- Primarily 3LPE/polypropylene (PP) with coat-tar enamel and sintered PE on older lines;
- Integrity management is based on ILI;
- External Corrosion Direct Assessment (ECDA) using a combination of DCVG and CIPS (to check CP);
- No SCC found on 3LPE/PP systems; and
- Minor disbondment issues but no corrosion problem as confirmed by ILI.

APA - Gold-fields (Australia)

- 1400 km 3LPE (coated 1996); and
- Good condition with 1.5A CP (for 1400KM) and nothing significant from ILI.

ENI

- Primary 3LPE/PP systems;
- ILI is the main integrity management tool;
- No SCC found;
- Minor disbondment on small diameter pipes due to poor application but no corrosion as confirmed by ILI; and
- Improper coating application and field joint installation was a problem.

Enbridge

- Enbridge has HPCC (HPPC) and FBE coated pipelines as well as coat-tar enamel, etc., on older lines;
- The integrity management system is the same for all systems;
- Primary tool is ILI with the frequency depending on the condition of the pipeline;
- CIS (CIPS) to check CP;

- Integrity digs;
- Enbridge’s position is to use HPCC/HPPC when the operating temperature is above 60 ^{o}C;
- A bitumen line (approximately 600 kilometers) with HPCC has been operating at 65–70 ^{o}C for 20 years without issues; and
- Reservation is on heat shrink sleeves, which have to be installed properly.

GRTgaz (formerly Gaz de France)

- Operated using 3LPE since 1996;
- SCC or CP Shielding hasn’t been found on this type of mainline coating; and
- Discovered one case of coating disbondment but it was a problem regarding FBE application at the mill and it was solved during construction.