The In-service Welding Subcommittee was called to order by the sub-committee co-chairs, Bill Bruce and Matt Boring, at 8:05 AM. The sign-in sheet was passed. A total of 32 participants attended the meeting. Those present introduced themselves and their affiliation.

The following is a description of the significant items that were discussed:

Incorporation by reference (IBR) of Appendix/Annex B CFR Parts 192 and 195 – The recent notice of proposed rulemaking, which allows procedures to be qualified to Section 5, Section 12, Appendix A, or Appendix B of API 1104) or ASME Section IX. The exclusive use of the word “should” in Appendix/Annex B was discussed, as was PHMSA’s position on the treatment of should statements in industry standards.

Interpretation requests – There were no new requests for interpretation that pertain to Appendix/Annex B that were passed down to the subcommittee. It was agreed that the subcommittee should review all responses to interpretation requests that pertain to Appendix/Annex B at every meeting.

The response to Interpretation No.1104-I-1131-15 (i.e., can a welder use an Annex B welder qualification to make welds on new piping?) was reviewed. The Interpretations Task Group (ITG) ruled that this was not acceptable because of the language in B.1 that limits the scope of Appendix/Annex B to pipelines that are in service. It was agreed that there are applications for which Appendix/Annex B welding procedures and welders are appropriate for non-in-service welds. Appendix/Annex B currently addresses longitudinal seam welds of full-encirclement fittings, which are not in-service if they are made into backing strips. Changes will be made to Annex B in the Twenty-second Edition to address this.

Improvement to Annex B for Twenty-second Edition – The majority of the meeting was spent discussion opportunities for improvement to Annex B for Twenty-second Edition of API 1104. It was agreed that the annex should be more independent of the requirements in the main body of API 1104 (i.e., the appendix should be more of a stand-alone part of the document). Other opportunities for improvement included the following:

- Clarification on the substitution of the tensile test for a nick break test for welder qualification for longitudinal seams in B.3.3 is required. The main body permits this for welder qualification.

- Table B.2 needs to be reformatted. The tensile section has merged cells which need to be unmerged so that the number of specimens cell extends over top of that cell.

- Longitudinal seam welds with backing strips are not technically in-service welds. We should clarify that a butt weld procedure qualified to Section 5 can be used to make this weld.
• Figure B.4 (Suggested Location of Test Specimens for Weld Deposition Repair) still needs to be improved by removing the “weld bead orientation” in Option 1. It was agreed that the use of actual photographs would be useful. This was confirmed to be possible by API staff.

• Table B.1 still needs to be renamed to reflect that it is also used for welder qualifications for weld deposition repairs

• The reference in B.7 to Section 10 should be removed and the repair and removal of weld defects for in-service welds should be addressed separately in Annex B.

• Input for Figures B.7 through B.12 is needed from the In-service Welding/Repair welding NDT Task Group. Access to some welds for NDT becomes restricted.

• Proposed language drafted by Matt Boring to clarify the requirements for in-service welder qualification was reviewed. For the Twenty-second Edition, these would be independent of Section 6. The working group established for this activity at the 2015 meeting will continue their work. Several attendees volunteered to help.

• Requirements for in-service repair of production girth welds were discussed. Both CFR 192 and 195 currently allow this, but no guidance exists for qualifying a procedure for this application of for executing such a repair. A new working group for this activity, headed by Bill Amend, was established.

• The need to clarify the essential variables for in-service welds was discussed. It was agreed that essential variables for in-service welds need to be defined in Annex B and not reference back to Section 5. A new working group for this activity, headed by Brad Etheridge, was established.

Other Discussion Items – The floor was opened to general discussion of relevant topics, some of which are opportunities for improvements to Annex B for the Twenty-second Edition of API 1104, including:

• Backing strips/backing bars for full-encirclement fittings.

• Welding procedure for low pressure/low flow applications. Do we need an alternative definition of what an in-service weld is when in some cases the production weld has more accelerated cooling than the in-service weld?

• Providing guidance pertaining to preventing burnthrough in Annex B. For example, a welder qualification test for thin-wall in-service welding applications (e.g., a weld on thin-wall pipe with pressurized air inside) could be developed.

• The availability of low-hydrogen electrodes in diameters less than 3/32 in. (2.4 mm) for in-service welding on thin-wall pipelines. Several suppliers were identified.
• Mechanisms for providing guidance pertaining to the application of Annex B. The inclusion of examples in Annex B was identified, as was a technical paper of journal article coauthored by the subcommittee.

• Preheat guidance during in-service welding. It was noted that an extensive PRCI report on this subject is available.

• Armadillo sleeves for reinforcement of damage in bend sections.

• Alyeska’s experience with pipeline damage caused by uncontrolled expansion of epoxy filler inside an encapsulation repair (see attached conference paper).

Plans for Going Forward – It was agreed that the working groups that were established would carry on with their assignments. In an effort to ensure progress, a teleconference for the entire subcommittee will be scheduled near mid-year (e.g., in the second half of April). Working group progress will be discussed and new working groups will be established for opportunities for improvement that are identified as high priority.

The co-chairs thanked everyone for their participation. The meeting was adjourned at approximately 12:00 PM.

Bill Bruce       Matt Boring
Co-Chairman      Co-Chairman
In-service Welding Subcommittee   In-service Welding Subcommittee
Lessons learned from encapsulation of pipeline hydrostatic testing vents and drains

by Alan S Beckett and Kevin Wigren
Alyeska Pipeline Service Co, Anchorage, AK, USA

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Organized by Clarion Technical Conferences and Tiratsoo Technical and supported by The Professional Institute of Pipeline Engineers
Lessons learned from encapsulation of pipeline hydrostatic testing vents and drains

SMALL BORE PIPELINE branch connections installed during pipeline construction for the purpose of hydrostatic testing air vents and water drains are a potential source of future leaks. A typical small bore branch connection (NPS 2 or smaller) may consist of a combination, integrally reinforced fitting with a threaded or seal welded plug, or a specialty, hot tap branch fitting. At some buried locations, a service valve may be left in place and protected by a corrugated metal pipe or concrete vault.

Operators of crude oil pipelines have provided additional protection from the potential risk of undiscovered leakage during service by installing leak boxes over the vent and drain appurtenances. Leak boxes may consist of in-service installation of a fully pressure rated encapsulation fabricated with standard piping components as defined by ASME PCC-2.

Lessons learned from a crude oil pipeline operator's experiences in encapsulating hydrostatic vents and drains and unexpected pipeline failure are presented.

A CRUDE OIL PIPELINE operator, in order to assess the integrity risk of leakage, radiographed high and low point THREAD-O-RING (T-O-R) fittings used for construction-era hydrostatic vents and drains at aboveground and buried locations on a 48-inch pipeline. The radiographs showed them in an indeterminate condition and confirmed T-O-Rs as potential locations for leakage. T-O-Rs were discovered with varying cap thread engagement, completion plug setting, and in some locations, service valves left in place.

Photo 1 shows the excavated as-found condition of a typical buried high point vent NPS 2 T-O-R. It is shown with the expected cap and welded tamper bar still in place after being in service more than 37 years. There was no evidence of crude oil leakage.

Photo 2 is a radiograph of an indeterminate condition found with a NPS 2 T-O-R. It shows the completion plug with its primary O-ring seal in place correctly, but the cap used as a secondary seal with poor thread engagement.

Following discovery of the T-O-R indeterminate conditions, to reduce integrity risk from leaks, the operator conducted a line-wide assessment to locate and install leak containment over all types of threaded connections attached to the pipeline that could potentially leak. A four-year project program was established to eliminate leakage risks of construction-era T-O-R fittings and other attachments by installing encapsulation type leak boxes.

Photo 3 shows an encapsulation installed on the bottom of pipe over a small bore valve assembly.

Encapsulation decision rationale

The decision rationale to install leak containment over T-O-Rs and other type branch connection attachments was based on whether they could be relied upon to not leak under normal pipeline operating conditions. Prior crude oil leaks at threaded connection locations (e.g., pipe nipples, small bore valves) led to a modest effort at spot-checking construction-era hydrostatic vents and drains T-O-Rs with radiography. The initial concern was heightened, and remedial actions put into place when spot checking easily accessible T-O-Rs found inconsistent engagement of the internal completion plug O-rings and threaded caps. The potential risk that these conditions could allow leakage was the basis
for installing leak containment over the T-O-Rs. Of the alternative methods deemed practical for leak containment, installing an encapsulation was judged to be the safest means and presented the lowest risk of causing a crude oil spill during installation. Approximately 100 T-O-R hydrostatic test high point vents and drains were identified as high risk and encapsulations were installed.

**Encapsulation design**

The typical encapsulation design consisted of a prefabricated pipe spool (dome configuration) about 15 inches in height set over T-O-Rs and welded directly to the pipeline, followed by filling the encapsulation with a two-part epoxy (resin and catalyst) commonly used for pipeline repairs. Epoxy was used as a volume filler to eliminate the potential of a dead-leg condition within the encapsulation in the event the T-O-R leaked. With an oil-filled dead-leg condition, there is a low potential for internal corrosion which increases the risk of an undetected oil leak from a future breach of the encapsulation. The purpose for filling the encapsulations with epoxy was solely based on mitigating the small leakage risk since encapsulations are not able to be inspected with in-line inspection tools.

The pipe spools consisted of a 12 inch long section of Schedule 40 ASTM A333-6 pipe with an ellipsoidal end cap welded to form an enclosure. The high point vent encapsulation design uses a single NPS ¾ THREAD-O-LET (T-O-L) installed in the vertical up position with the end cap located at the top to allow for epoxy filling, epoxy expansion, and epoxy curing gas venting, which would then be plugged and seal welded after completion of the epoxy curing process. Other low point drain and side connections use multiple T-O-L connections on the encapsulation body for filling and venting.

The encapsulations were welded to the pipeline with a full penetration single-bevel groove weld with a full-fillet cover weld in a similar manner as installing a typical hot tap stub-on branch connection. The GTAW and SMAW welding processes were used in accordance with an in-service welding procedure qualified in accordance with API 1104, Appendix B. The weld joint detail met the requirements of ASME B31.4, Figure 404.3.4.3.

Other encapsulation design configurations were installed on the bottom of pipe for low point drains and also side of pipe applications. All encapsulation pipe spools were hydrostatic tested to 1800 psig for four hours before installation. Due to the attachment location of some T-O-Rs in relation to the pipeline’s longitudinal seam and, in a few instances, discovery of a small amount (depth) of external corrosion, two sizes (diameters) of encapsulations were installed. The majority of the 100 encapsulations installed over construction-era T-O-Rs were 6-inch diameter with four that were 10-inch diameter. One 12-inch diameter and one 4-inch diameter encapsulation were installed over service valve assemblies.

Encapsulations were installed primarily with the T-O-R centered within the encapsulation circumference or in certain cases offset to one side to accommodate the interaction with the mainline pipe's longitudinal seam and/or to avoid external corrosion. Ten-inch encapsulations were used when the T-O-R was attached close to the mainline pipe longitudinal seam so the attachment weld would cross the seam as near to perpendicular as possible and to avoid welding along the toe of the seam weld. This was precautionary to minimize additional heat input (thermal cycle) into the heat-affected zone of the submerged are weld and to avoid additional weld toe stress concentrations.

**Pipeline failure**

With the intention of providing leak containment, by installing a 10-inch diameter encapsulation over a non-leaking aboveground NPS 2 T-O-R, a crude oil pipeline operator experienced a failure of the mainline pipe material within the encapsulation. The encapsulation was installed on a 48-inch
diameter, 0.462-inch W.T., API 5L X65 pipeline operating at about 500 psig. No crude oil spilled or apparent visual structural damage to the pipeline resulted from the failure.

The failure occurred during the final installation step when a two-part epoxy (resin and catalyst), as recommended by ASME PCC-2, Article 2.4, “Welded Leak Box Repair,” was used to fill the annular space within the encapsulation, thereby eliminating any potential liquid dead-leg volume created by the encapsulation if the T-O-R leaked. The two-part epoxy had been used previously as a non-compressible filler material for pipeline Type A and Type B snug-fit and stand-off repair sleeves successfully without incident.

**Incident scenario**

The field crew welded the 10-inch encapsulation and filled it with two-part epoxy using the supplier's standard resin and catalyst kit without mixture volume modification. The 10-inch encapsulation required approximately five gallons of mixed epoxy. It was completely filled with a single mix in one continuous pour. Inert aggregate was not used as a third optional part along with the two-part epoxy kit that is available by the supplier. A clear vinyl vent tube was connected to a T-O-L vent on the top of the end cap and then attached to a small clear plastic containment bag which was left in place as the epoxy cured. The next day (about 12 hours after the initial pour) the crew returned to remove the tube and bag and install a NPS ½ steel threaded plug into the T-O-L which had been left open to allow room for expanding epoxy and curing gases to escape. The crew observed a small amount of crude oil in the containment bag, as well as within the vent fitting, after removing the vent tubing. Cured epoxy could also be seen at the bottom of the T-O-L fitting along with a small amount of pooled crude oil that continued to reappear after removal. After removing the crude oil weep and cleaning, the plug was installed in the T-O-L and threads seal welded, thus completing the encapsulation installation with it ready for recoating and re-insulation.

Photos 4, 5, and 6 show the T-O-R before installation of the 10-inch encapsulation, after installation, and the failed mainline pipe with the T-O-R intact that was expelled into the operating pipeline. A 10-inch encapsulation was required due to the proximity of the pipe's longitudinal seam. This is the same T-O-R that is shown in the radiograph of Photo 2.

**In-line inspection evaluation**

After the failure incident, to verify the structural integrity of the remaining 6-inch and 10-inch T-O-R encapsulations, a thorough review of in-line inspection (ILI) caliper and high resolution MPL data from a previous 2013 tool run was performed to locate any other encapsulation locations that may have shown indications of mainline pipe wall deformation, significant tearing, or loss of pipe material. The ILI data for over 90 T-O-R encapsulation locations was reviewed and found undamaged. Figure 1 shows the ILI 3-D caliper data at the failure location shown in Photos 4 and 5, whereas Figure 2 shows a normal T-O-R location with a 10-inch encapsulation installed.

**Failure investigation**

A comprehensive failure investigation was conducted by Stress Engineering Services, Inc. (SES), located in Cincinnati, Ohio of the incident. SES was to determine the probable failure process and epoxy-related factors that caused the pipeline material contained within the 10-inch encapsulation's internal perimeter along with the intact T-O-R to be expelled (punched-out) into the operating pipeline during the epoxy curing process.
The failure investigation consisted of three parts: 1) Structural Evaluation, 2) Epoxy Evaluation, and 3) Full-Scale Evaluation. One of the key outcomes of the investigation was to calculate the pressure needed to cause the mainline pipe to fail within 6-inch, 10-inch, and 12-inch encapsulations. The investigation findings were utilized to assess whether the remaining encapsulations posed a significant integrity threat to the pipeline.

**Structural evaluation**

The structural evaluation consisted of performing 2-D and 3-D (both continuum and shell models) finite element analyses (FEA) of 6-inch, 10-inch, and 12-inch encapsulations. The primary purpose of the FEA was to analytically predict the ductile tearing type of cracking and final failure of the mainline pipe material by gross yielding and ductility exhaustion [1] observed by visual and metallurgical examination of the 10-inch encapsulation failed pipe material: fracture surfaces. It is very important to note, that there was no evidence from the metallurgical examination that the cause of the failure was associated with a fracture from hydrogen cracking in the weld heat-affected zone, unacceptable hardness, or weld defects commonly associated with in-service welding.

The FEA models included the effects of the full three-dimensional geometry of the mainline pipe/encapsulation weldment, elastic-plastic behavior of the encapsulation and mainline pipe materials, pressure loading of the mainline pipe and encapsulations, and full nonlinear large-deflection deformation behavior of the mainline pipe and encapsulations. Figure 3 illustrates the principal stresses due to internal pressure for 10-inch encapsulation.

The FEA answered three key questions about internal pressure within the encapsulations to cause structural damage or complete failure of the mainline pipe:

**Question 1: What is the pressure that would fail the encapsulation itself?**

The pressures are:
- 6-inch: ≈ 6,800 psi
- 10-inch: ≈ 6,500 psi
- 12-inch: ≈ 4,500 psi

**Question 2: What is the pressure to permanently deform the mainline pipe inward by a 1/8-inch and 1/4-inch which are detectable by ILI?**

The pressures are:
- 6-inch: ≈ 7,200 psi (1/8-inch), ≈ 10,000 psi (1/4-inch)
- 10-inch: ≈ 2,300 psi (1/8-inch), ≈ 2,600 psi (1/4-inch)
- 12-inch: ≈ 1,500 psi (1/8-inch), ≈ 1,800 psi (1/4-inch)

**Question 3: What is the pressure required to fail the mainline pipe wall?**

The pressures are:
- 6-inch: > 6,800 psi with or without a weld discontinuity at the weld root toe
- 10-inch: ≈ 3,500 psi with weld discontinuity at weld root toe, ≈ 4,500 without weld discontinuity at the weld root toe
- 12-inch: ≈ 2,750 psi with weld discontinuity at weld root toe, ≈ 3,600 without weld discontinuity at the weld root toe

It was concluded from the structural evaluation of the 6-inch encapsulations, which were the majority of the 100 installed, that the pressure required to fail the mainline pipe is greater than the pressure required to fail the encapsulation body. The "punch-out" resistance of the 48-inch, X65 pipe material with 500 psig internal pressure is far greater than the rupture hoop strength of the 60 ksi
minimum tensile strength 6-inch encapsulation pipe material. For 10-inch and 12-inch encapsulations, the mainline pipe fails at a lower pressure than required to rupture the encapsulation body. For those sizes, if the mainline pipe wall were to fail, the encapsulation pipe pressure boundary would remain intact and no oil leakage from the mainline pipe or encapsulation would be expected.

**Epoxy evaluation**

The epoxy evaluation consisted of performing epoxy swelling studies in the presence of crude oil, examination of cure temperature profiles, and corrosion testing using the same two-part epoxy and using the same resin-to-catalyst mix ratio used to fill the encapsulations in the field. One of the significant findings of the epoxy evaluations, contrary to intuition, was that even though the temperature rises during the exothermic curing reaction, epoxy doesn't expand significantly during curing; it actually shrinks [2]. This finding is very significant to understanding the failure process in that it removes thermal expansion of epoxy as a contributing factor for the cause of the pipe material failure within the 10-inch encapsulation.

Laboratory epoxy testing work established that different curing temperature profiles were developed in different zones during the curing process; the highest temperature is reached in the center of the largest uninterrupted volume of epoxy (typically at the encapsulation centerline halfway between the top of the T-O-R and encapsulation cap). During laboratory testing of the full-scale 10-inch encapsulations, thermocouples were placed according to Figure 4. Location TC97 exhibited the highest temperature. Figure 5 details the temperatures achieved in measured zones and the corresponding pressure measured within the 10-inch encapsulation.

The primary reason for the elevated temperatures and subsequent high gas pressures is the large volume of epoxy contained within a small surface area. Large uninterrupted volumes of curing epoxy with relatively small surface area have poor heat transfer to the surroundings. Therefore, the initial curing exothermic reaction can reach a temperature in excess of the epoxy's thermal degradation temperature. At this point, thermal degradation which is also an exothermic reaction, in turn feeds further thermal degradation of the epoxy. As the epoxy degrades it liberates gaseous products that have significant volumes. As a side-note, when the inert aggregate was added to 5-gallon epoxy tests, curing temperatures were reduced drastically and resulted in temperatures during curing that did not lead to thermal degradation of the epoxy.

Radiographs of the epoxy-filled encapsulations showed the epoxy in its final cured condition is in a fractured condition from natural shrinkage, thermally degraded condition, or solid block of epoxy. In all three conditions, swell testing concluded the epoxy will not generate significant post-curing loads as a consequence of aging (with or without crude oil exposure). The epoxy was also found to undergo minimal swelling in the presence of crude oil and NGLs, eliminating another potential source of internal encapsulation pressurization in the event of crude oil leaking through the T-O-R.

To further evaluate the concern for dead-leg corrosion, if oil seepage was to occur within the epoxy-filled encapsulations in any three of the final cured conditions, corrosion evaluations were performed. The pH of the epoxy degradation products was found to be 8.0 (slightly basic) and therefore not a corrosion concern. In addition, corrosion testing in the form of immersion mass-loss and salt-spray testing was conducted on coupons extracted from the full-scale encapsulation test pipe materials. The test results indicated the epoxy coating on the un-prepped internal encapsulation surfaces will generally serve as an acceptable corrosion barrier (internal coating of encapsulation surface). Therefore, even without possible full coverage on internal encapsulation surfaces, the risk of leakage resulting from corrosion is very low.
Full-scale evaluation
To fully understand the failure process and epoxy-related factors of the mainline pipe failure, twenty-one full-scale tests were performed. The test matrix in Table 1 identifies the tests that were performed by SBS.

These tests duplicated the encapsulation designs, encapsulation and mainline pipe materials, spool fabrication methods, the epoxy mixing ratio(s), and pouring practices used to install 6-inch, 10-inch, and 12-inch encapsulations in the field. The only exception was no internal pressure was used within the 48-inch pipe for any of the full-scale tests. The configuration of a 10-inch full-scale test assembly is shown in Photo 7.

During the full-scale epoxy tests, the encapsulation and mainline pipe were instrumented. The internal epoxy and external steel temperatures, internal encapsulation pressure, and the mainline pipe and encapsulation deflections and strain data were obtained. A limited number of tests were performed using only hydrostatic pressure to validate the test instrumentation and also to determine the detection sensitivity of the phased-array ultrasonic testing (PAUT). PAUT was also used during two full-scale 10-inch encapsulation hydrostatic tests to determine pre- and post-testing weld acceptance and to detect the onset of ductile tearing (crack) initiation.

Photos 8 through 10 show the typical test instrumentation setup and pouring of mixed epoxy.

After tests were performed, the encapsulations that did not fail were sectioned to observe the final condition of the epoxy, to determine the extent of any pipe wall deformation, and locate any observed ductile tearing cracks. Photos 11 and 12 show the results of one 10-inch encapsulation that failed by epoxy leakage before complete failure of the pipe material in contrast to Photo 13 which shows complete failure of the internal pipe material from within a 10-inch encapsulation.

Tests using epoxy were conducted with the same vent sizes and locations on the encapsulations as were installed in the field. Vents were sealed mechanically with pipe plugs after the epoxy is poured. Some tests were performed with vents open. Tests with several rich and lean catalyst epoxy mix ratios and some tests with backside cooling to duplicate the heat sink capacity of flowing crude oil were performed.

The tests demonstrated that the pipeline failure occurred as a two-step process that was directly related to the internal gas pressures from the epoxy curing reaction and from thermal degradation of the epoxy. It is important to note that mainline pipe failure only occurred within the 10-inch encapsulations and no measurable deformation, tearing or cracking was found with the 6-inch encapsulations and one 12-inch encapsulation that were tested. For those epoxy-filled encapsulations which did not fail, it was demonstrated that the elevated internal pressures were temporary and dissipated shortly after the curing reaction was completed and the epoxy cooled. All encapsulations that did not cause failure of the mainline pipe within the encapsulation held zero pressure or a small vacuum at the end of testing.

The full-scale epoxy tests confirmed the primary findings from the epoxy evaluations: when the peak temperature achieved during curing of the epoxy remains below about 550°F, failure of the pipe material within an encapsulation is not likely to occur.

Integrity discussion
At the time of this paper additional mechanical and fracture testing of specimens from the full-scale test encapsulations is underway. The purpose for these tests is to obtain the actual material and
fracture properties of the mainline pipe and encapsulation materials. Actual material properties are needed to validate the FEA results which were based on published properties. Validation of the FEA will confirm the understanding that the structural integrity of the pipeline has not been harmed by the remaining encapsulations.

It was found by full-scale testing that epoxy exothermic reactions are complex and when used in pipeline repair applications are dependent on the thermal heat sink capacity of the pipeline and ambient conditions. Without reaching curing temperatures exceeding about 550°F, internal gas formation due to epoxy degradation is insufficient to obtain high pressures to cause failure of the mainline pipe within encapsulations, but may be sufficient to cause failure of the encapsulation body. Once curing is complete and the temperatures return to ambient, no additional pressure is generated by off-gassing of the cured epoxy. In all full-scale tests no internal pressure or a small vacuum remained within the encapsulations. This is a very significant finding in that it substantiates conclusively there is no structure integrity risk due to high pressures remaining within any size encapsulation on the pipeline.

An evaluation of the failure investigation's structural evaluation results in combination with the epoxy and full-scale evaluation results support the important understanding that no injurious structural damage occurred in the remaining encapsulations and is further supported with the negative results found from a limited post-failure field investigation using radiography and PAUT. A random small number of aboveground and buried 6-inch, and all the 10-inch and 12-inch encapsulations were inspected and found without detectable mainline pipe deformation or relevant crack indications. From these field inspections and the findings from the failure investigation, the structural integrity threat of the remaining encapsulations on the pipeline is judged negligible.

Along with the understanding that no structural integrity threat remains, the corrosion testing results showed that any degradation epoxy products within the encapsulations are non-corrosive and that the epoxy coated surfaces are an acceptable corrosion barrier in the unlikely chance of a significant leak occurring within the encapsulation. The integrity threat from internal corrosion is considered a very low risk.

Further considerations

Attachment weld design, installation practices and procedures, as well as other considerations must be taken into account before using epoxy-filled encapsulations for leak containment of construction-era hydrostatic testing vents and drains on pipelines.

Attachment weld design

Pipe spool type encapsulations used as leak boxes over hydrostatic testing vents and drain fittings (i.e., T-O-R, T-O-L) require attachment welds designed and sized to provide sufficient strength to withstand a pressure breach of the enclosed fitting. Encapsulation attachment welds must be designed in accordance with the governing construction code in a similar manner as required to install a branch connection, and made using a qualified in-service welding procedure. Seal welding or using only a fillet weld to attach encapsulations may not be adequate for full pipeline pressure containment if a leak would occur within the encapsulation. The encapsulation itself requires the pressure capacity of the pipeline's maximum operating pressure (MOP). Pressure design calculations for the governing construction code (i.e., ASME B31.4) apply.

In general, design requirements found in ASME PCC-2, Article 2.4, "Welded Leak Box Repair," should be followed whenever encapsulations used as leak containment are installed over pipeline hydrostatic testing vents and drains.
Installation practices and procedures

Installation practices for encapsulations filled with two-part epoxy on in-service pipelines require consideration of the heat transfer effects of large volume-to-small surface area applications and the heat sink capacity of the pipeline. In some applications, supplemental external cooling or the addition of inert aggregate may be required to prevent excessive curing temperatures with the potential to reach above 560°F and subsequent and undesirable epoxy thermal degradation.

Detailed installation procedures should be prepared and followed by craft workers. Controls should be provided within installation procedures to ensure craft workers follow the epoxy supplier’s mixing instructions explicitly to prevent mixing ratios that can produce excessive curing temperatures (e.g., hot mix with catalyst-rich).

Craft qualifications

Craft workers used to install and fill encapsulations should be qualified under conditions representative of the field application. Qualifications under DOT Operator Qualification rules apply for these installations.

Epoxy limitations

Epoxy filler materials without inert aggregate are not optimum when it is necessary to achieve 100% fill of the void volume because of the epoxy’s high viscosity. Without the inert aggregate, incomplete filling is possible and more pronounced shrinkage of the epoxy occurs. In its final cured condition it may also have random multi-branching cracks and fissures.

Also, for bottom of pipe drain encapsulation like the one shown in Photo 14, complete filling of an encapsulation is impossible; leaving a void (dark area in the radiograph) at the top of the epoxy fill line as shown in Photo 12.

Lessons learned

Several high value lessons were identified from key findings from the failure investigation’s structural, epoxy, and full-scale evaluations. These lessons are useful for liquid or gas pipeline operators to consider when using epoxy filler materials in conjunction with pipeline repairs. They are especially beneficial as shared knowledge to other operators within the oil and gas industry to prevent a similar pipeline failure incident occurring with possibly more severe consequences. They provide valuable insights gained from one pipeline operator’s experiences and failure investigation findings that can be useful to others that are considering using epoxy filler materials within encapsulations (leak box type applications) or as non-compressible filler materials for repair sleeves.

Lesson Number 1. When using epoxy filler materials without inert aggregate, consideration must be taken to the adverse consequences of an encapsulation (leak box) design in which a large volume of epoxy is contained within a small surface area. The failure incident resulted from the elevated internal pressure within the encapsulation caused by thermal degradation of the curing epoxy at temperatures exceeding 550°F. Because of the large volume-to-small surface area ratio of the 10-inch encapsulation (63% greater than the 6-inch encapsulation), temperatures higher than 550°F are likely, with undesirable consequences of a large amount of gas generation and high internal pressure build-up. With this high pressure, failure of the encapsulation itself or pipeline is possible. Therefore,
adequate heat transfer must be addressed in the encapsulation design, again primarily because of
the geometry of the encapsulation design, not the physical volume of epoxy.
To offset the consequences of gas generation in large volume-to-small surface area encapsulations,
use of an additional inert aggregate with two-part epoxy products is highly recommended to lower
epoxy curing temperatures. Strong consideration should also be given to reducing the size of a single
epoxy pour by filling encapsulations in two or possibly three pours, with curing in between, rather
than a single monolithic pour.

In addition, fill and vent locations, and size, in encapsulation designs should be established to
minimize the potential for blockage and potential pressure build-up.

**Lesson Number 2.** Epoxy filler materials used in a new or novel applications and/or configurations
require recognition that additional engineering design review and/or prototype testing is prudent and
should be performed. High reliance on prior successful applications of two-part epoxy (without inert
aggregate) filler material for repair sleeves without recognition of the inherent application
differences nearly resulted in a significant crude oil spill and personnel injury. Prior to use as a filler
material, pre-packaged pipeline repair epoxy kits should be demonstrated suitable for the specific
application, such as encapsulation or repair sleeve designs. It is recommended to perform application
specific full-scale mock-ups to demonstrate installation procedures, verify acceptable results, and
identify potential hazards.

**Lesson Number 3.** Follow the epoxy supplier’s most current installation instructions, with special
consideration to application limitations for two- or three-part epoxy products. Most epoxy pipeline
repair products have been designed and formulated for a specific application. If the designed
application is different than the intended application, additional cautions should be taken. Even with
clear usage instructions, consult with the epoxy supplier’s technical representative or a qualified
independent third party prior to using epoxy for pipeline repair applications.

As learned from the failure investigation when using two-part epoxy for a new application (such as
an encapsulation that was extrapolated from previous successful use of epoxy as a filler material for
repair sleeves) a small but very significant change was required, but overlooked. In hindsight, the
lack of recognition to use an inert aggregate by a thorough engineering evaluation beyond the epoxy
supplier’s standard recommendations and instruction limitations would have prevented the failure
incident.

It is important to note, epoxy supplier’s labeled instructions on product containers may not be
complete or detailed enough to cover all types of application conditions or physical limitations for the
use of the epoxy. In error, hazards beyond personnel exposure limitations associated with using
exothermic reacting materials were not identified prior to using epoxy in a different application
resulting in the failure. The product labeling for the pipeline repair epoxy products used in the
failure incident had no physical volume restrictions or thickness limitations appearing in the
labeling. Nor was there a reference or warning to use an inert aggregate to offset the thermal
degradation that is possible with large volume-to-small surface area applications.

**Lesson Number 4.** Precautions addressing potential high temperatures and pressures must be
considered when using epoxy filler materials in repair sleeve and encapsulation designs. Design of
encapsulations should consider not only the pressure design of the pipeline but also the internal
pressures that can be generated by curing epoxy. Encapsulation designs must fully account for the
gaseous byproducts naturally generated during the initial chemical curing reaction and the high
temperatures associated with large volume-to-small surface area pours of epoxy. Furthermore, the
potential hazard that might occur if the expansion vent(s) became plugged due to epoxy curing in the
vent must be accounted for.
ASME PCC-2, Article 2.4, "Full Encirclement Steel Reinforcing Sleeve and Piping," paragraph 4.2 recommends pumping filler material (epoxy or polyester resin) into the annulus after repair sleeves have been welded in place, provided the annular gaps are large enough to allow the filler to flow into all voids. There are no precautions stated to address the potential hazard of collapsing the internal pipe material from pressure developed by curing epoxy identified; nor are there any precautions stated within ASME PCC-2 Article 2.4. Precautions should be taken when using exothermic reactive materials for these types of repairs.

Conclusions

Failure of the pipeline material within the 10-inch epoxy-filled encapsulation could have been prevented by more rigorous engineering review, better hazard recognition, and prototype testing.

Recommendations to consider before using exothermic reacting filler materials (i.e., hardenable, non-compressible epoxy or polyester resin) for pipeline repair applications included within ASME B31.4 Table 451.6.2.9-1, Note 3 and ASME B31.8 repair options are:

1. Qualify pipeline repair designs that use exothermic reacting filler materials by engineering evaluation and consider prototype testing before field application.

2. Conduct a thorough process hazard review to address all credible problems that could arise.

3. Evaluate the potential for new and unique pipe material failure modes.

4. Establish a craft worker qualification for epoxy-filled encapsulation (leak box) and repair sleeve applications.

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References

4. ASME PCC-2, Article 2.4, Repair of Pressure Equipment and Piping.
5. ASME PCC-2, Article 2.6, Full Encirclement Steel Reinforcing Sleeves for Piping.
7. ASME B31.4, "Pipeline Transportation Systems for Liquids and Slurries"
8. ASME B31.8, "Gas Transmission and Distribution Piping Systems".
Photo 1 - Buried high point vent NPS 2 T-O-R with cap and welded tamper bar.

Photo 2 - Radiograph of T-O-R with completion plug fully-seated, but cap threads not fully engaged.
Photo 3 - Encapsulation installed over a bottom of pipe drain valve.

Photo 4 - Aboveground high point vent NPS 2 T-O-R with cap and welded tamper bar before installation of 10-inch encapsulation shown in Photo 5. Note: The proximity of the longitudinal seam which required using a 10-inch encapsulation.
Photo 5 - 10-inch encapsulation installed over T-O-R in Photo 4.

Photo 6 - Pipeline material from within 10-inch encapsulation with intact T-O-R after traveling over 400 miles in pipeline.

Figure 1 - ILI 3-D caliper data showing missing mainline pipe material from within 10-inch encapsulation shown in Photo 5.
Figure 2 - ILI 3-D caliper data showing typical NPS 2 T-O-R location with 10-inch encapsulation and mainline pipe material intact.

Figure 3 – 2-D axisymmetric continuum model mainline pipe deformations and principal stresses at 3,000 psi encapsulation internal pressure.

Figure 4 - 10-inch thermocouple locations.