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REPORT OF A COATING FAILURE ON A 16-INCH OIL PIPELINE UNDER WET CO_2 SERVICE

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ABSTRACT

Presented in this paper is the report describing the analysis and investigation of a failure that occurred on a Client's 16-inch (400 mm) oil pipeline in South America involving severe wet CO_2 service. The investigation findings revealed that the I.D. pitting of the 16-inch (400 mm) pipe sample occurred from exposure of the pipe I.D. to corrosive produced fluids at an area of internal coating failure. Inadequate surface preparation and surface contamination before applying the I.D. field coat was the primary cause for the internal coating failure. Based on the sample examined, the operator could anticipate additional I.D. field joint failures and take actions to inspect the pipeline to identify such sites. More details regarding this analysis and the follow up work initiated are given in this paper along with conclusions and recommendations.

Keywords: blisters, carbon dioxide corrosion, coating, failure analysis, inhibition, oil pipeline.

INTRODUCTION

A 16-inch (400 mm) gathering line that transported produced fluids to a central production facility (CPF) failed at a site of internal pitting on the bottom of the line. The failure was at a low point in the line close to a field welded pipe joint.

The line transported oil containing substantial water and CO_2 at approximately 200 F (93 C) and 200 psi (1.4 MPa) total pressure. The CO_2 partial pressure was 72 psia (0.5 MPa). The fluid production contained 58,000 banels per day water and 19,000 banels per day oil. The buried carbon steel line was internally and externally coated and was externally cathodically protected. It was believed that the internal coating would give adequate corrosion protection and requirements for chemical inhibition would be minimal.

The internal coating consisted of a shop applied, catalyzed fusion bonded epoxy and a field applied catalyzed fusion bonded epoxy over the field weld joints. The field coating was applied using a remote controlled robot. The abrasive blasting operation was also supposed to lightly abrade and feather approximately one inch from the shop coating. Following welding, the robot was supposed to blast the pipe I.D. with steel shot to remove weld flux, vacuum the spent beads, and coat the I.D. while the pipe was externally heated to approximately 400 F (204 C) using induction coils. Field application procedures were to manually abrasive blast the pipe I.D. at the shop coat cut-back area and weld I.D. to a SA 2 (near white) finish with a 1-3 mil (0.025 – 0.076 mm) anchor profile. The length of the line was 14 km which required a total of 1400 welded and coated joints.

The client requested *InterCorr* to conduct a laboratory analysis of the failed pipe sample to determine the cause of failure. The client specifically requested to identify: (1) If the coating was not applied properly or if it had disbonded over time and, (2) based on the cause of the pipe failure, what was the potential for additional failures in the wet CO_2 / oil production environment.

LABORATORY ANALYSES

Laboratory analyses performed on the pipe sample included: (1) Visual observations, (2) Metallographic examinations of the field and shop coating, (3) Scanning electron microscope (SEM) and energy dispersive spectroscopy (EDS) analysis of the coating and foreign material, (4) Paint thickness measurements, (5) Paint adhesion testing and, (6) Fourier transform infrared (FTIR) and (7) Differential scanning calorimetry (DSC) analysis of both the field and shop coats.

OBSERVATIONS

Visual Observations

An approximately 15-inch long pipe sample was received for analysis (Figure 1) containing the failure area. An elongated, through-wall pit was present on the bottom of the pipe at the shop/field-coating interface (Figure 2). The pipe O.D. at the through-wall hole is shown in Figure 3.

Many distinct areas of I.D. coating failure were observed, particularly at the shop/field coat interface. The bottom of the pipe was scratched and abraded, with some coating removed (Figure 2). The coating on the top of the pipe had also failed at the shop/field interface (Figure 4), although not as severely as at the bottom. Coating scratches and abrasion were not observed on the top of the sample I.D.

Figures 5 shows a close up view of representative I.D. coating damage and a through-wall pit. The pit initiated at the shop/field coating interface on the upstream side of the sample butt weld. Similar, less severe damage was observed at the interface on the other side of the weld. Small, pinhole porosity can be seen in the I.D. coating at the weld. The cut-back area of the coating on the pipe (area between the butt weld and the shop coating) was approximately one inch wide on either side of the weld; however, in some locations it was less. Figure 6 shows damaged coating on the opposite side of the through-wall pit after removing part of the disbonded coating with a knife blade. A black material was found under the coating. Several blisters were also present. A blister, after opening, also contained a black material. Prying with a knife revealed that the black material was on top of the shop coating.

A full length strip from the top and bottom of the pipe sample was bent 180 degrees over a mandrel at -20 F (-29 C) in an attempt to fail non adherent or loosely bonded coating and to check for contamination under the shop and field coating. Figure 7 shows the bottom bend sample. The field coating was observed to separate from the base metal in large pieces. Both separations at the base metal/coating interface and intra-coating delamination were noted. A large area of delamination at the base metal occurred. The pipe sample I.D. contained an oily sheen underneath the field coat. Visual examination of the pipe side of a paint chip that separated at the weld (See Figure 8) showed that it contained a black foreign material and an oily residue. The part of the chip that delaminated from the base metal did not exhibit any anchor profile.

Figure 9 shows a cross section of the coating at the shop/field coat interface. The shop coat does not appear to have been feathered and contains foreign material under the coating. The void in the shop coating suggests that material may have been trapped beneath the shop coating during application or infiltrated along corrosion undercutting at the edge of the shop coat. Figure 10 shows a close up of a cross section of the field coating. It is extremely foamed at the base metal. The void rating at this location is 9, with 10 being the worst rating on a 1 to 10 scale, based on API RP 5L7 (Recommended Practices for Unprimed Internal Fusion Bonded Epoxy Coating of Line Pipe).

Figure 11 shows another shop/field coating interface cross section. The coating at this location contains foreign material between the shop and field coating overlap, including steel shot, and contamination beneath the shop coating. A third location is shown in Figure 12. The field coating is beneath the shop coating at this location, clearly showing that the edge of the shop coating was not bonded when the field coating was applied.

Paint Thickness Measurements

Pipe I.D. coating thickness measurements was made with an Elcometer. Shop coating thicknesses ranged from 0.030 inch (0.76 mm) to over 0.040 inch (1.01mm), the upper limit of the instrument. The field coating ranged from 0.017 inch (0.432 mm) to over 0.040 inch (1.01 mm). Both the shop and the field coating thicknesses were much thicker than the 0.015 inch (0.381 mm) to 0.025 inch (0.635 mm) specified by the vendor for these coatings. Also apparent is that the field coating was thicker on one side of the weld than the other. The coating on the side containing the through-wall hole was the thinner of the two sides.

SEM/EDS Analysis

SEM/EDS analysis was conducted on several paint chips and mounted samples to verify the composition of the foreign material observed. The presence of titanium, a common component of shielded metal arc electrodes, supports that the material was weld flux, especially as the field coating does not contain titanium. EDS analysis of the SEM sample showed many elements to be present. The large iron and oxygen peaks qualitatively suggest iron oxide corrosion products. The sodium, chlorine, silicon and calcium may originate from the produced fluids. Not explained by base metal, corrosion products or the produced fluid is the presence of significant lead. The oil used in the paint application equipment may be a source of the lead and should be investigated to verify if it contributed to this contamination. The field work summary reports state that oil contamination from the hydraulic welding alignment unit was a continuing problem.

FTIR/DSC ANALYSIS

FTIR/DSC analysis was conducted on the shop and field coatings to verify the type of coating system used. The analysis showed that the shop coating was an bis-phenol epoxy resin containing carbonate filler. The carbonate, combined with the EDS shop-coating reference scan, suggests that the filler was calcium carbonate. DSC analysis of the shop coating showed that it was properly cured, based on $T_{g\ 2\text{-}1}$, although the T_g analysis result (97°C) was somewhat less than that stated by the resin vendor (105°C).

FTIR/EDS analysis results for the field coating showed that it also was a bis-phenol epoxy resin, but without the carbonate filler. The resin was properly cured, based on $T_{g\ 2\text{-}1}$.

DISCUSSION

The available evidence points to a combination of factors that resulted in the pipe sample failure. The operating temperature of the line did not seem to be a major factor. Based on this investigation, the primary factor appears to be inadequate surface preparation of the field coating substrate. While the presence of steel shot shows that the I.D. was blasted after welding, it was not effective in removing I.D. contaminants. Contamination under the shop coating at the cut back area, combined with evidence of the field coating underneath the edge of the shop coating suggests that the shop coating was not bonded to the pipe I.D. when the field coating was applied. The lack of an observed anchor profile on the underside of the disbonded field paint chips and lack of evidence that the shop coat was feathered suggests that the abrasive blasting operation designed to remove I.D. scale and provide a near white surface preparation either was not conducted or was conducted poorly. The surface contamination, including evidence of oil contamination, is suspected as a primary cause for foaming of the field coat. The raised edge of the shop coating, combined with a high degree of voids in the field coating provided areas at the shop/field coating, interface where corrosive produced fluid could migrate to the base metal, resulting in the pitting observed.

FOLLOW-UP CORROSION PROTECTION IN WET CO_2 SERVICE

Do to contractual demands it was imperative that the pipeline be placed back into service as soon as possible. Therefore, a remediation strategy was needed that would require a minimum of downtime and also provide a high assurance that future failures were not occur. To investigate the possibilities of further leaks on the pipeline, the client conducted follow-up tests to assess the viability of simply repairing the leak and provide added chemical treatment to handle any other areas of coating damage.

General and pitting corrosion rate measurements were made in the field using linear polarization resistance (LPR) probes and a portable potentiostat instrument in a sidestream apparatus. Corrosion inhibitor treatments were started immediately after the leak to reduce the internal corrosion. To lay a protective film on expected localized bare steel areas the inhibitor dosage started with 50 ppmv based on the water cut in the 16-inch line. Using the sidestream corrosion instruments the inhibitor dosage was optimized to about 15 ppmv. At this dosage level, the side stream corrosion tests showed general and pitting corrosion rates of less than 1 mpy (0.025 mmpy).

The pigging frequency was also examined and increased to twice a month using soft oversized polyurethane cup pigs for all internally coated lines. In addition, the pigging sludge from the pig catcher was analyzed to see if internal coating flakes could be found indicating that more localized bare steel areas existed. No additional coating flakes were found during the investigation and the assumption was made that the failure in the pipeline was most likely an isolated case. Additionally, external ultrasonic inspection of 20 joints showed no coating damage or evidence of pitting corrosion.

Further investigations were made into the events surrounding the failure. It revealed that the welded field joint at the failure was coated and welded during a four day heavy tropical rain and poor QA/QC supervision resulted in the disbonded coating at this weld. Furthermore, the oil contamination underneath the coating was from the hydraulic welding alignment unit. This unit was used to align the individual pipe joints for field welding and the mentioned black residue was blasting grit and oil that was not effectively removed by the coating robot used in the field.

Corrosion inhibition and pigging are ongoing on this line and no more failures have been experienced on this pipeline to date even though the produced water increased to more than 70 percent.

CONCLUSIONS

Based on the results of this investigation and the follow up work carried out by the operator the following conclusions were made:

1. The 16 inch (400 mm) pipe sample failed from internal pitting corrosion at an area of coating failure on the ID of the pipe. This was due to localized CO_2 corrosion.

2. Coating failure was caused primarily by surface contamination and inadequate surface preparation of the field joint and feathering of the shop applied internal coating before applying the field coating.

3. Another factor in the failure was the location of the failed section of pipe (at a low point in the line). This contributed to the failure by allowing water to accumulate under low flow conditions, which would locally increase the severity of corrosion once the coating failed.

4. Corrosion inhibitor treatments with a water soluble corrosion inhibitor were recommended and set up by the client immediately after the failure.

5. The pigging frequency was increased to twice a month using soft oversized polyurethane cup pigs for all internally coated lines. This would minimize subsequent coating damage while helping to remove accumulations of water from low spots.

6. In addition, the pigging sludge from the pig catcher was analyzed to see if additional coating flakes could be found indicating that more disbonded internal coating areas existed.

7. Corrosion inhibitions were optimized using linear polarization (LPR) measurements and potentiometric measurements via a sidestream attached to a mini separator. These field, side-stream corrosion measurements were very useful in optimizing the inhibitor dosage to a maintenance level and to provide assurance that corrosion in the line had been successfully controlled.

8. Pigging and corrosion inhibition is ongoing on this line and no further leaks have been experienced with this line to date.

ACKNOWLEDGMENTS

The authors wish to express their thanks to their colleague Dr. Russell D. Kane for his extensive reviews and contributions during the performance of this work.

Figure 1 - Sample, approximately 15-inch long pipe containing the failure area.

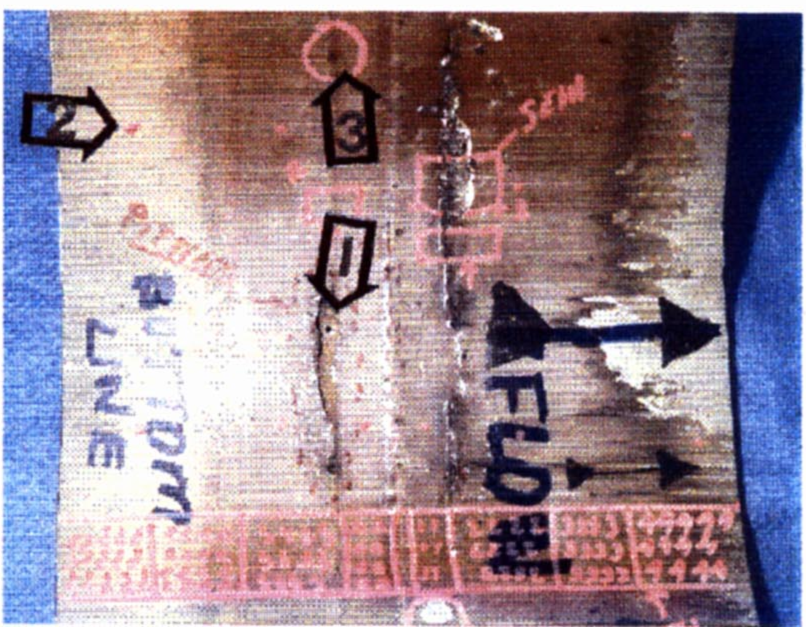


Figure 2 - An elongated, through-wall pit was present on the bottom of the pipe at the shop/field-coating interface

Figure 3 - O.D. at the through-wall hole.

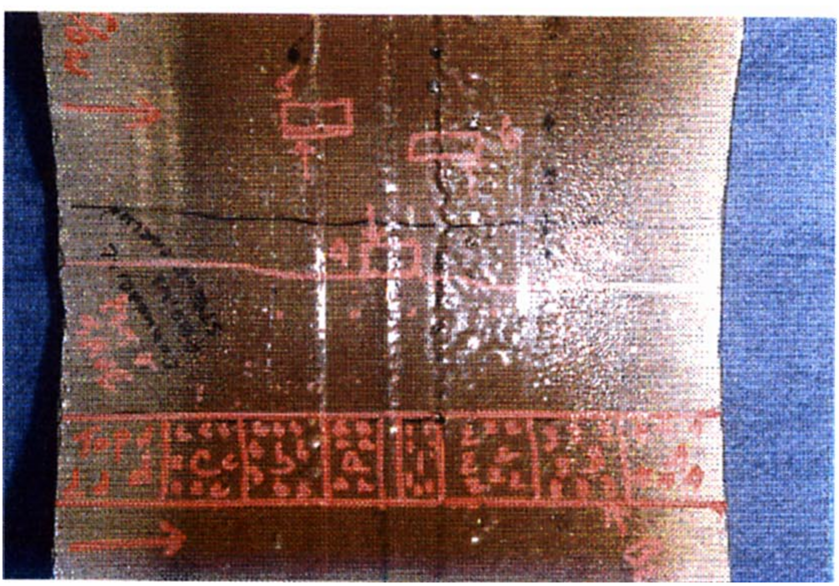
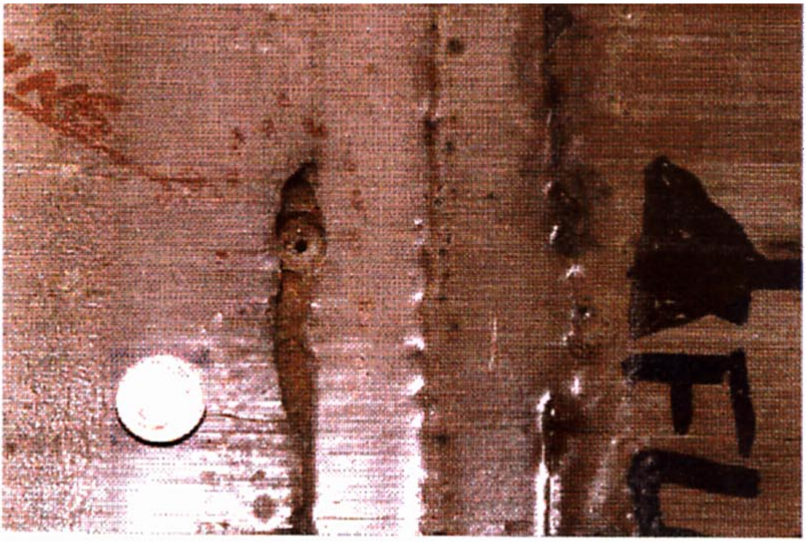


Figure 4 - As-received top half of pipe ID showing coating damage and locations of samples removed for analysis (in red).



Figures 5 - Close up view of elongated pit shown in Figure 1.

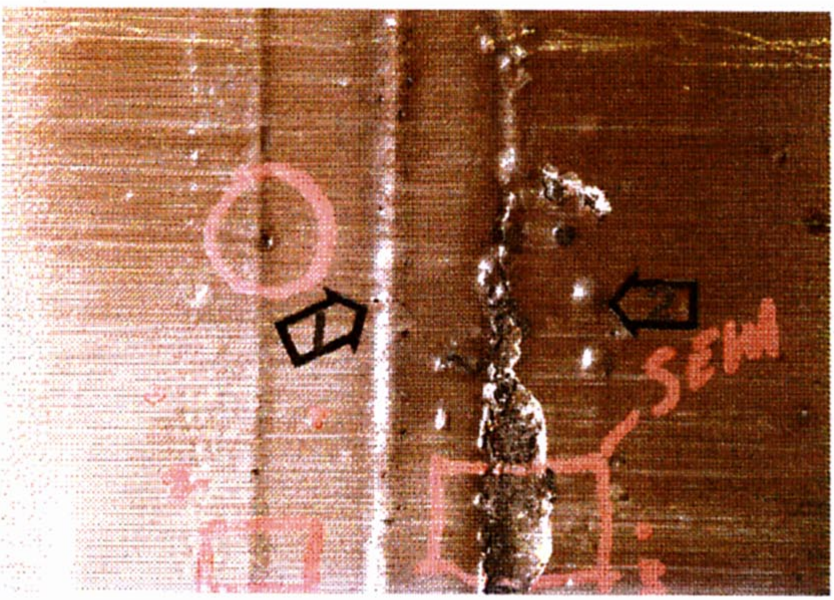


Figure 6 - Damaged coating on the opposite side of the through-wall pit after removing part of the disbonded coating with a knife blade

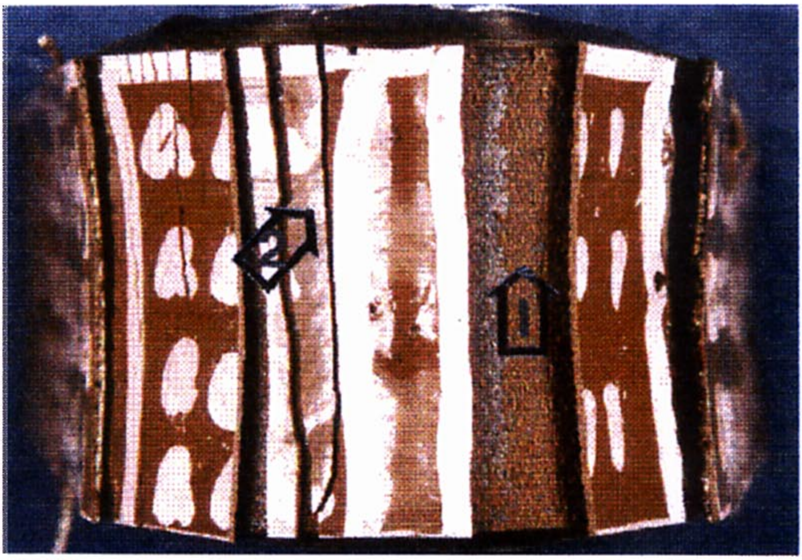


Figure 7 - Bottom bend sample after bending at -20F (-29C)

Figure 8 - Visual examination of the pipe side of a paint chip that separated at the weld showed that it contained a black foreign material and an oily residue.

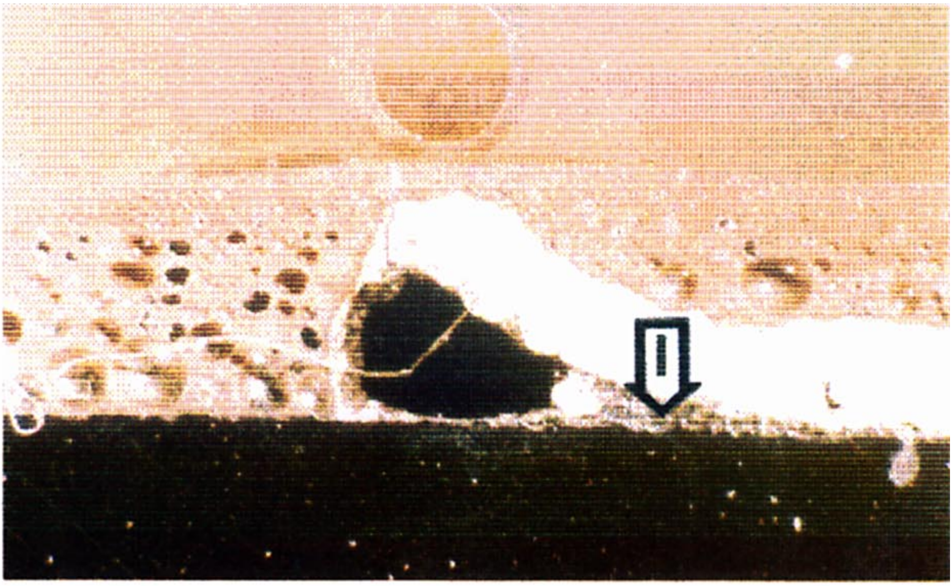


Figure 9 - Cross section of the coating at the shop/field coat interface.

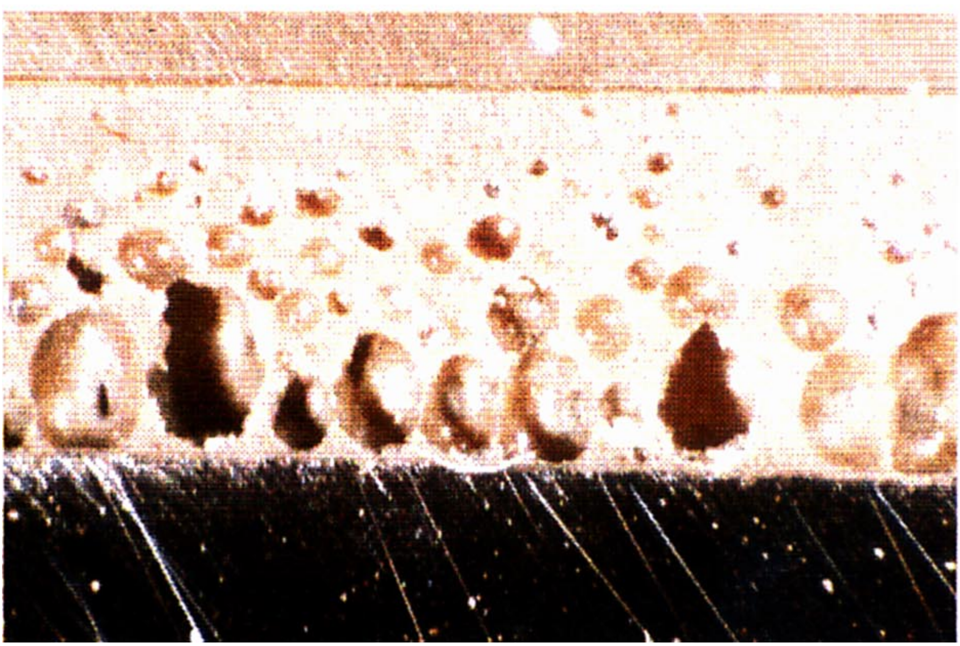
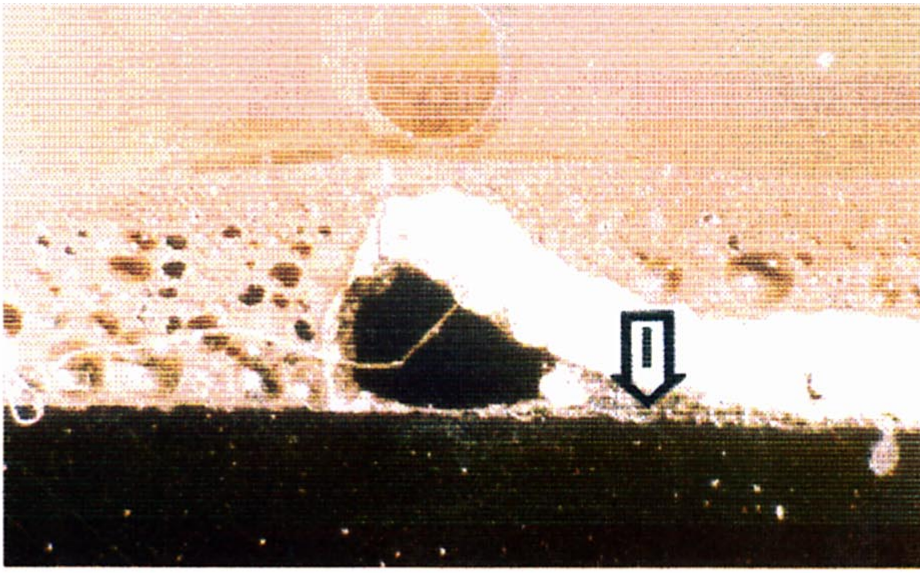


Figure 10 - Another shop/field coating interface cross section.



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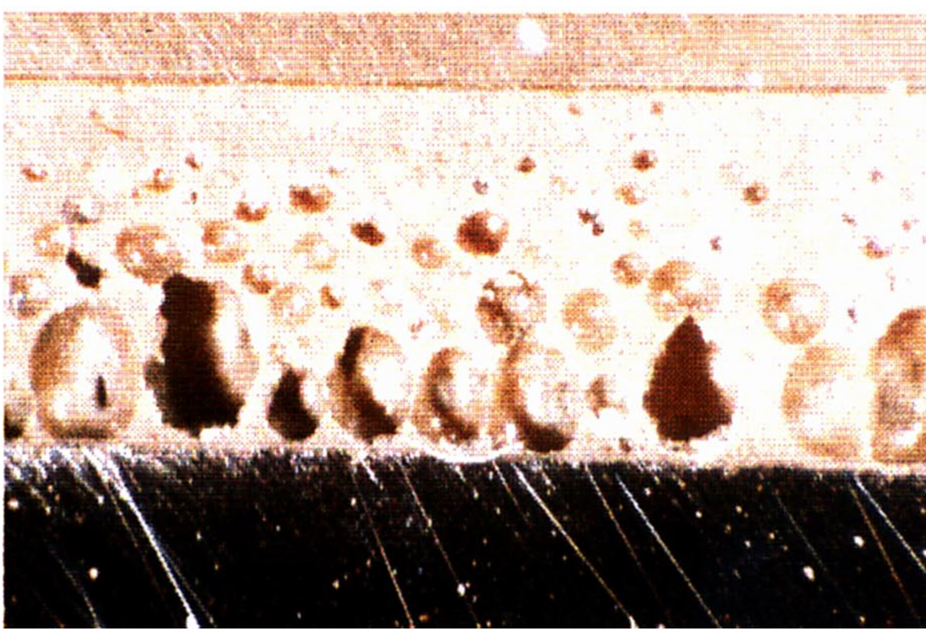

Figure 12 - Sample at cut back showing field coating underneath the shop coat (1), and foreign material underneath the shop coat (2)