Internal Metallic Pipe Coatings for the Geothermal Industry

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Abstract

This paper describes an on-going test program being conducted at CalEnergy's Salton Sea facilities to evaluate the performance of thermal spray coatings as corrosion barriers when applied to interior pipe walls. The ability to apply these coatings to internal pipe surfaces has recently been developed. Investigators are attempting to validate the suitability of these coatings with aggressive geothermal fluids, as well as identify the procedures necessary to assure a successful coating application. In April 2002, a carbon steel pipe with an Inconel 625 coating was placed into service in the surface piping at one of CalEnergy's production wells; results from this exposure will be available in the fall 2002. It is anticipated that a coated steel pipe will replace the cement-lined or nickel alloy piping currently used. The Department of Energy's Geothermal Program funds this work. Raymond LaSala is the DOE-HQ program manager; Jay Nathwani is the project manager at the DOE-Idaho Operations office.

Background

The extreme geothermal operating environments force the use of exotic materials for piping and components, or require frequent replacement of these components if common materials of construction are used. The application of thermal spray coatings to modify the surfaces of exposed steel (or other commonly used alloys) exposed to the geothermal environment has the potential to provide the same corrosion and scaling protection as the exotic materials, but at a much lower cost. Thermal spray coatings are successfully used in acidic, aggressive environments in the petrochemical industry. This experience has shown that a testing program in the aggressive environment is needed to assure success for these coating systems.

The thermal spray process uses a heat source to bring a powder or wire to a molten or near-molten state, which is then propelled by the gas stream to impact the surface that will be coated. In the application being tested the gas stream is heated by an arc-plasma, non transferred arc system. The deposited surface is characterized by layers of metal splats with a matrix that is created with each pass of the spray gun. Ideally the application of the coating will minimize the voids, inclusions (unmelted metal particles), and metal oxides are among the metal splats in the matrix. These voids, inclusions and oxides reduce the strength of the coating. A coating must have sufficient bond strength to the substrate, low porosity, and an absence of cracks. Previous corrosion studies that tested thermal spray coatings have shown that microcracks and/or interconnected porosity will allow elements in the fluid to penetrate the coating down to the substrate and adversely react with the substrate.

The capability to thermally spray coatings on the interior surface of piping has just recently been demonstrated. This capability has the potential to be used in the field to repair or "retrofit" existing piping systems, as well as in the fabrication of new pipe. The INEEL is working to bring the prototype system to the field and to increase the spray system's capacity up to that required for industrial scale fabrication.

Meetings held with CalEnergy(the operator of the Salton Sea geothermal facilities)staff identified areas of their plants that would benefit from the application of robust coatings on interior surfaces. CalEnergy indicated that their primary concern was the buildup of scale (iron silicate) and the associated restriction of flow, (corrosion could also occur subsequent to the scaling). Currently, cement linings are used to prevent the silicate in the fluid from bonding with the iron in the carbon steel pipe. Requirement documents were produced that described the environment and process conditions. A brine chemistry for a Salton Sea well is shown in Table 1. Based upon these conditions, a materials evaluation report was created for the specific application, recommending candidate materials and methods to apply the materials. A test plan to evaluate the recommended materials was reviewed and approved by CalEnergy.

Corrosion Test Program

The initial testing utilized a corrosion coupon tree for inserting test coupons into operating systems. The coupons and coupon tree were fabricated at Flame Spray Industries under the direction of Zatorski Coating Company(ZCC). The coupon tree and the four sets of coupons are shown in Figure 1. The coupon tree was installed at CalEnergy's Salton Sea facilities in December 2001 (Figure 2). The initial coating materials selected for the CalEnergy coupon test (Table 2) were all known to perform well in environments with similar pH, temperature and pressure.[1, 2,3] There were 3 coupons each of Ultimet, IN625, Hastelloy C276, and 4777. The samples were 1.0 inches in diameter and 4.0 inches long with tapered ends. The coupons had a

3/8 inch diameter hole in their center. The carbon steel substrate was pressure grit blasted with virgin 24 mesh aluminum oxide grit at 80 PSI. The resulting surface had a surface roughness of greater than 300 Ra. microinches. Each coupon was coated 0.015 inches thick. The performance of these materials as sprayed coatings in saturated fluids moving at velocity were unknown. The corrosion coupon tree for the initial test (December 2001 through February 2002) was installed at the juncture of the two wellhead flow streams coming together into a single pipe. This area is the most severe test environment because the coupons are located in the turbulent, two-phase flow stream, which has the highest temperature and the greatest amount of entrained particulate at the highest velocity. The corrosion coupon tree consisted of a ring of IN625 alloy used as a gasket between the pipe flanges. On the internal diameter, a tongue was bent into the direction of flow. A flat piece of C-276 2 inches wide by 18 inches long was welded onto the tongue. Four holes, approximately 4 inches apart were drilled to 1/4-inch diameter for passing the 3/8 inch C-276 bolts through. The coupons were separated on the bolt with Teflon shoulder washers. The bolt was fastened with two C-276 nuts.

Test Results

Following a 1200 hr exposure period, the coupons were removed in Febuary 2002 and examined. Only one set out of the four sets of coupons (Ultimet coating) remained on the coupon tree when it was retrieved (Figure 3). The fate of the other three sets is unknown. The high vibration of the wellhead piping may have caused the nuts or bolts to loosen. Examination of the coupon tree flange ring revealed cracks on the inner diameter of the ring, which could be due to piping vibration (fatigue). The weld that attached the flat plate to the ring was also cracked. Stress corrosion cracking has been found to be possible in these systems.[4]

The Ultimet coupons are shown after exposure in Figure 4. There was a hard, tightly adherent surface deposit on the Ultimet coupons and the corrosion coupon tree. This scale was analyzed and was found to be silicate based with every other element of the liquid phase shown in Table 1 being present. The deposit was thicker on the corrosion coupons than on the C-276 plate material of the corrosion tree. One possible explanation for this is the coupon tree material has a better initial surface finish than the corrosion coupons, which may affect the scale deposition rate.

Sections of the coupons were prepared for examination by vacuum impregnation in epoxy and then polished. The surfaces were examined with optical and Scanning Electron Microscopy (SEM). Figure 5 shows a light microscopy image of an unexposed Ultimet coating on carbon steel as deposited by the plasma arc process. The image shows the layers of the metal matrix. Within these layers, the voids, inclusions and metal oxides are evident among the metal splats. The amount of voids, inclusions and oxides is at an acceptable level for performance of the coating. Figure 6 is a SEM micrograph of the Ultimet coating with bars inserted showing the coating thickness, which averages 16 mils (0.016”). Figure 7 shows the surface of the Ultimet coated coupon after 1200 hours exposure. The geothermal solution has penetrated the coating and has corroded the carbon steel substrate. The formation of this corrosion product caused disbonding of the Ultimet coating from the carbon steel. The geothermal scale was then able to penetrate the coating and plate over the carbon steel corrosion and the underside of the unbonded Ultimet coating.

For the second round of testing, a coated pipe spool was installed downstream from the location of the first corrosion test installation. The coupon tree from the initial test was reinstalled to the same location as before. The location of the pipe is felt to be more representative of the general run of pipe in the facility. The interior of this pipe spool and the flange faces were coated with

IN625. The exterior of the four new corrosion coupons were also coated with IN625. This alloy offers the highest bond strength and density of all the coatings tested. It is felt that these characteristics would make an improved coating as compared to the Ultimet coating even though the IN 625 coupons were not retrieved for analysis. Two of the four corrosion coupons were coated with the IN 625 alloy to a thickness of 0.015 inches and two coupons were coated to a thickness of 0.025 inches. One of each of these coupons was sealed with an oil-modified phenolic sealer. This sealant will slow the penetration of the geothermal fluid through the coating by sealing any path through the coating.

The pathways through the coating could be initiated at sites on the surface of the coating such as unbonded areas or a void. There is no data from the coupons that have been tested to surmise was caused initiation of the pathway or how much time had passed before initiation occurred. Access to a test loop would be required for more exact observations to be made. Coupons of the same materials could be staged at different time intervals for evaluation of surface conditions.

Large Scale Pipe Test

The pipe spool will be exposed to the geothermal operating conditions for approximately 5000 hrs and is scheduled to be removed for examination in Oct 2002. The 16-inch schedule 80 pipe, (0.844"wall) was 11.86 feet long. This length included the 25-inch outer-diameter flanges. The pipe was coated with an IN 625 coating with a nominal thickness of 0.014 inches. An arc-plasma gun mounted on an arm was used to apply the IN 625 material in multiple passes onto the interior of the pipe. Approximately 0.004 inches of coating was applied per pass. A wire arc-plasma gun was chosen to eliminate powder handling and feeding issues. The mating surfaces of the flanges were coated with a hand-held version of the arc-plasma gun. Approximately 26 pounds of IN 625 feedstock material were used to coat this pipe. Tabs were sprayed with the pipe for metallographic analysis.

This coating was not sealed since the selection of sealers for this application is still in process.

Future Plans

INEEL will continue to study corrosion issues in geothermal plants for possible applications of thermal spray coatings to protect carbon steel pipe in geothermal environments. Testing of these coatings will continue in aggressive geothermal environments to evaluate their performance in establishing both appropriate materials and application methods and specifications. The coupon test results suggest that the coating surface finish is an important parameter in geothermal applications in terms of scale formation, as well as pressure drop. These tests will include densification of the coating by glass bead peening or other peening methods, and the use of sealers.

References

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Table 1 Salton Sea Geothermal Chemistry

pH 5.5

480 ^{0}F	370 psi	Velocity 10 ft/sec
TDS	230,000 ppm	(Range from 18% to 35%)
Cl	127,000 ppm	
Na	47,000 ppm	
Ca	20,000 ppm	
K	12,000 ppm	
Fe	1,000 ppm	
Mg	1,000 ppm	
S	50 ppm	
Silicate	500 ppm	Severe scaling occurs
Non condensables	3%	CO_2, N, H_2S

Table 2 Material Compositions of Corrosion Coupons

	625	**C-22**	**Ultimet**	**AMS 4777**
Cr	21%	22%	26%	7%
Co	1%	-	Balance	-
Ni	Balance	Balance	6%	Balance
Mo	9%	13%	5%	-
Nb	4%	-	-	-
Fe	5%	3%	3%	3%
W	-	3%	2%	-
B	-	-	-	3%
Mn	-	-	1%	-

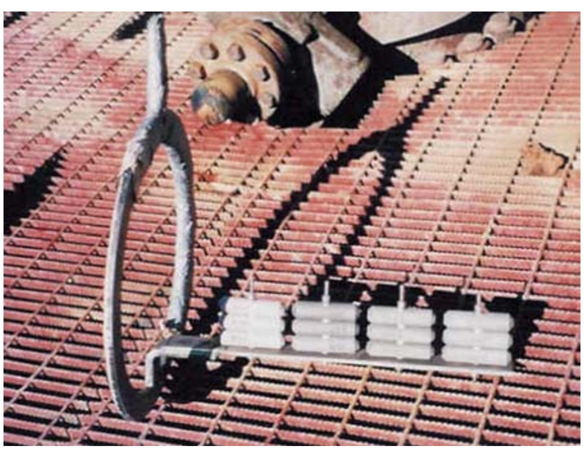

Figure 1. Corrosion Coupon Tree

Figure 2 Insertion of the coupon tree in VON-4 pipeline, Salton Sea

Figure 3, Coupon tree with Ultimet coupons

Figure 4 Ultimet coupons after 1200 hours

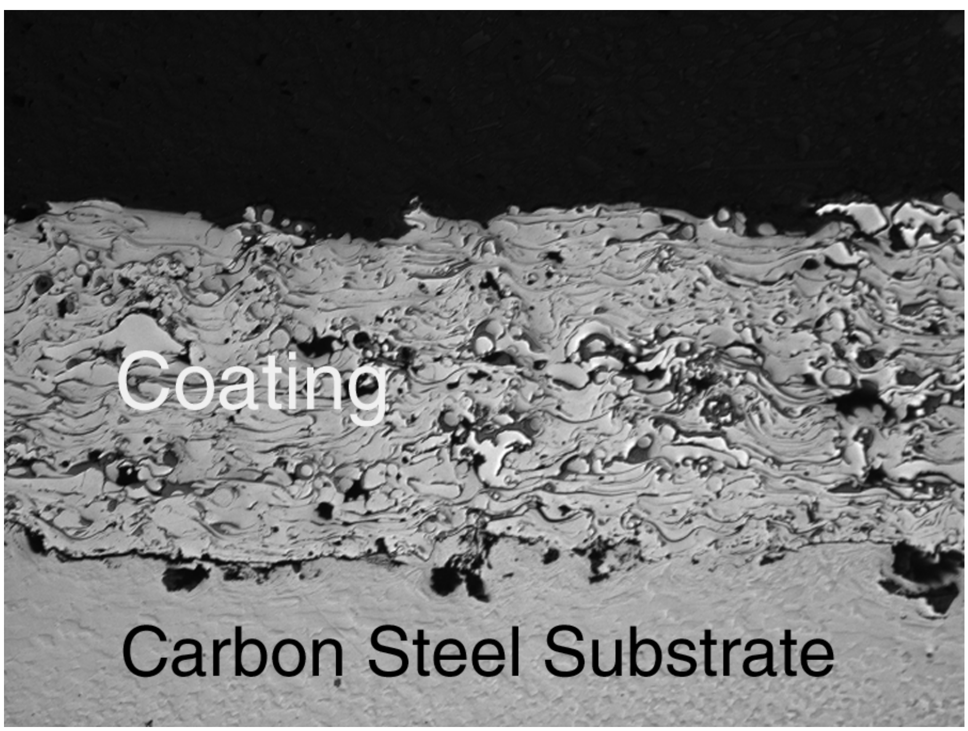

Figure 5, Optical micrograph of Ultimet coating (approximately 100X)

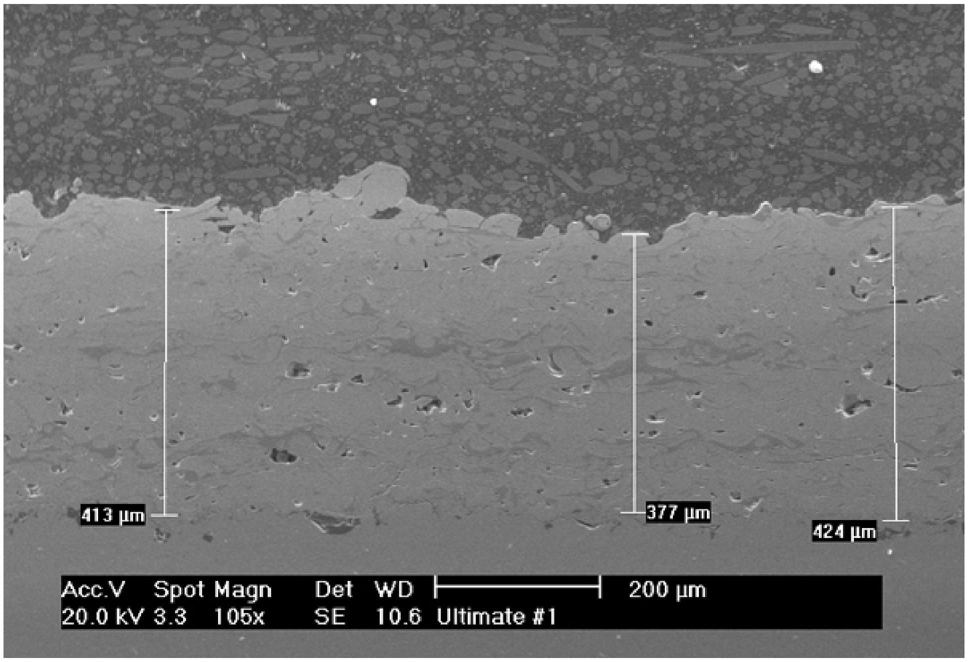

Figure 6, SEM micrograph of Ultimet coating

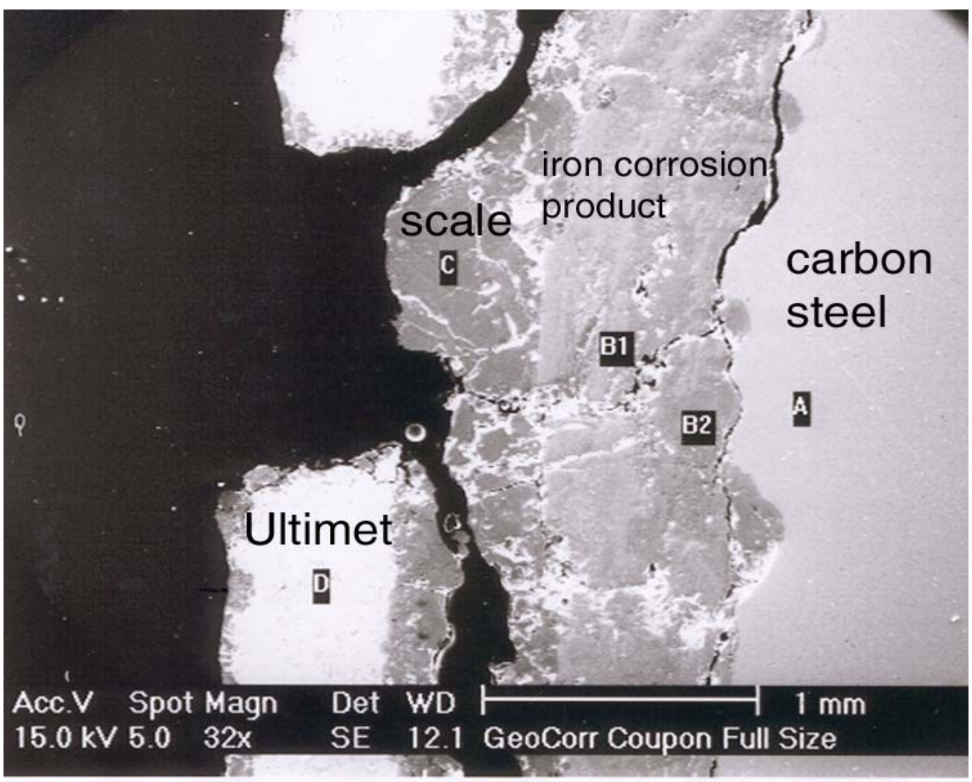

Figure 7 Ultimet coated coupon after 1200 hours exposure