FBE Found Effective After 30 Years Of Service

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(Author note—Nap-Gard® is the functional coating line of DuPont Powder Coatings, USA.)

Exploratory inspections — conducted as part of the risk assessment process — of two fusion bonded epoxy (FBE)-coated pipeline segments installed more than 30 years ago have provided valuable, positive information of historical performance and indications of future FBE coating performance. Data derived from laboratory tests indicated that the coating was properly applied in the mid 1970s and field inspections revealed good-to-excellent adhesion and limited disbondment. The inspections also provided additional validation of the ability of the FBE coating to work in unity with cathodic protection to provide superior pipeline protection.

Although records of the FBE manufacturer[1] indicate that this mid-1970s FBE coating formulation has gone through several subsequent revisions in order to give better corrosion protection and mechanical properties, this older generation of FBE installed more than 30 years ago is still performing well. There are no indications of significant coating degradation and it appears that there are many years of remaining life on the FBE system.

Exploratory excavations and inspections of pipelines initiated through integrity management programs can provide valuable information about the long-term performance of early generation FBE coating systems. There have been many changes and developments in FBE coating technology since the 1970s. Evaluations of earlier generations of FBE can provide additional performance validation that may yield a greater degree of confidence with current formulations.

Assessment of the integrity of gas pipeline and storage field facilities performed utilizing a comprehensive risk management program can identify numerous physical pipeline characteristics and operating conditions that can be utilized for evaluating risks and prioritizing integrity work. Concerns about changes in operating conditions noted during risk assessments can initiate further work activity such as exploratory coating inspections for gathering additional data in order to more thoroughly assess integrity risks.

While performing a routine risk assessment of storage field pipelines, increases in field withdrawal temperatures were noted. The temperature increases were due to recent storage field capacity expansions. Increased service temperatures relative to the age of the coatings and coating service temperature limitations prompted exploratory excavations and inspections to determine current coating conditions.

The data gathered from these inspections would be used to further evaluate risks and determine integrity management needs and associated timing for the established needs. The inspections would also provide information about the potential impact of high temperatures on coating performance going forward. The scope of this article is limited to discussions on the exploratory inspections, coating performance observations and related testing of two FBE-coated pipeline segments in a storage field.

Original Construction

The two pipeline segments were coated with FBE at a pipeline coating mill in Houma, LA in 1975. The FBE used was Homegard 100, one of the first generation Nap-Gard® primerless FBE systems. Records of the FBE manufacturer1 indicate this formulation had undergone several subsequent revisions in order to give better corrosion protection and mechanical properties.

The pipeline segments were installed for storage field service in 1975. Inspection of coating application at the coating mill was performed by pipeline company personnel and pipeline installation was overseen by company inspectors. Repairs to coating holidays at the coating mill were performed with epoxy "melt sticks." Repairs due to damage that occurred during construction and on girth welds and field joints were performed with a cold applied tape that contained a bituminous compound with thermoplastic fibers bonded to a vinyl film.

Inspection Site Selection

Selection of the two inspection sites was based both on the importance of the pipeline to the field gathering system and the maximum gas temperatures flowing through the pipelines during withdrawal periods. Site A was selected specifically due to elevated gas temperatures up to approximately 76.7°C (170°F). Site B was selected due to its importance as a mainline header critical to the operation of the entire north section of the storage field.

The pipeline coatings were inspected visually for any surface discontinuities such as blisters and other signs of potentially disbonded coating. If moisture was present beneath blisters, the pH level of the moisture was tested for indications that cathodic protection current was reaching the pipe surface. The pipe surface beneath the blisters (if present) was also inspected for signs of corrosion.

Adhesion tests were performed using ASTM D6677-01 (Standard Test Method for Evaluating Adhesion by Knife) at random points along the pipeline and beneath the tape coating at field joints. Surface profile depths were gathered as an indication of degree of surface preparation when conditions allowed for an accurate measurement. Finally, coating thickness measurements were gathered along the entire length of the exposed pipeline. FBE samples were taken from sites A and B for detailed laboratory evaluations.

Pipeline Data

The pipeline at Site A is a 10.75-inch, .562 wall thickness, 5LX52 grade pipeline with a Maximum Allowable Operating Pressure (MAOP) of 3,000 psig. Historical withdrawal gas temperatures on this lateral range from approximately 46.1°-48.9°C (115º-120ºF) between 1975 and 2003. After an expansion in 2003, this lateral was subjected to temperatures up to approximately 76.7°C (170ºF) on an intermittent basis during withdrawal seasons (typically winter months).

Depth of cover at the inspection location is approximately 48 inches. This pipeline has been cathodically protected with an impressed current system since shortly after installation. See Table 1 for cathodic protection pipe to soil potentials over the last 15 years near the inspection site.

Table 1: Cathodic Protection History

	Site A On(V_{cse})	Site B On(V_{cse})
1990	-1.390	—
1991	-1.313	—
1992	-1.252	-1.415
1993	-1.587	-1.317
1994	-1.604	-1.345
1995	-1.574	-1.383
1996	-1.640	-1.425
1997	-1.571	-1.274
1998	-1.593	-1.300
1999	-1.521	-1.315
2000	-1.432	-1.153
2001	-1.553	-1.364
2002	-1.331	-1.207
2003	-1.492	-1.367
2004	-1.568	-1.285
2005	-1.361	-1.343

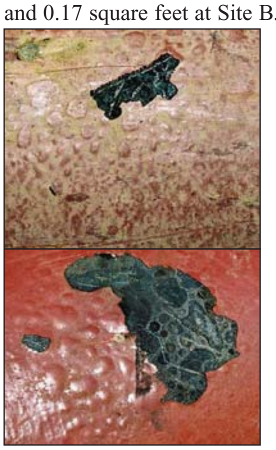
Pipe to Soil "On" Potentials versus Copper/Copper Sulfate (CSE) Electrode

The pipeline at Site B is a 12.75-inch, .625 wall thickness, 5LX52 grade pipeline with MAOP of 3,000 psig. Historical gas temperatures on this lateral range from approximately 48.9°-54.4°C (120º-130ºF) between 1975 and

2003. After an expansion in 2003, this lateral was subjected to gas temperatures up to approximately 60°C (140ºF) intermittently during withdrawal season. This pipeline has been cathodically protected with an impressed current system since shortly after installation. Depth of cover at the inspection location was 54 inches. See Table 1.

Visual Inspection

The length of pipe excavated and exposed at Site A was approximately 35 feet. The length of pipe excavated and exposed at Site B was approximately 50 feet. Visual inspection over the entire length of the exposed areas revealed only a single isolated colony of blisters on each exposed pipeline. The amount of blistering at Site A was approximately 0.13% of total surface area and approximately 0.16% of total surface area for Site B. The total surface area of each blister was 0.135 square feet at Site A and 0.17 square feet at Site B.



Photos 1 & 2: Magnetite coating beneath coating blisters. Site A (top) Site B (bottom)

Removal of the disbonded area at the blisters for both pipelines revealed a black oxide residue that prior studies indicate is a magnetite film Fe_3O_4[2,3]. There was no measurable wall loss beneath either of the blisters and the pH of the moisture under the blisters was greater than 10 (photographs 1 and 2). Both high pH and the presence of the magnetite film appear to support past work which suggested that FBE does not shield cathodic protection current[4,5]. Similar behavior was observed on FBE-coated pipelines in the Middle East Subkha Area[6]..

Coating Thickness Tests

Coating thickness tests were performed with a calibrated magnetic pull-off gauge. Thickness measurements at Site B were consistent over the exposed length of pipeline and ranged from approximately 10-12 mils. Coating thickness measurements at Site A ranged from 10-12 mils consistently across one joint of pipe and ranged from 23-25 mils on another joint of pipe at the same site. The joint of pipe with coating thickness beyond the norm compared to the other exposed joints was likely coated earlier at the coating mill prior to making the final specified coating thickness.

Adhesion Tests

Coating adhesion tests were performed utilizing ASTM D6677-01. The rating scale on this test method ranges from 0-10 with a total of six even numbered ratings (i.e. 0, 2, 4, 6, 8, and 10). According to the rating system, a rating of 0 indicates the least degree of adhesion (poor) and 10 indicates the best degree of adhesion (excellent). The degree of adhesion is graded according to the size of the fragments removed when performing the test method.

Adhesion tests at Site A were performed on both the 10-12 mil thickness coating and the 23-25 mil thickness coating. Adhesion of the 23-25 mil thickness coating was superior and rated a 10. Adhesion on the joint of pipe with 10-12 mils of coating was rated an eight which is considered good.

Adhesion tests at Site B were performed in the pipe body and beneath the field joint where tape coating had been installed during original construction. Adhesion on both the pipe body and the field joint were both within a rating of eight, although the FBE at the field joint showed slightly better adhesion (photos 3 through 6).

Photo 3: Site A — Joint with coating thickness range of 10 to 12 mils and an adhesion rating of 8.

Photo 4: Site A — Joint with coating thickness range of 23 to 25 mils and adhesion rating of 10

Photo 5: Site B — Adhesion test at field joint with a rating of 8. Note: The photograph shows the surface after multiple passes to remove coating.

Photo 6: Site B — Adhesion test in pipe body with a rating of 8.

Surface Profile

Surface profile measurements were only possible at Site B since coating remnants remained due to the excellent adhesion of FBE at Site A (Photograph 7). Site B surface profile was measured at a depth of 3.2 mils.

Lab Evaluations

Typical evaluation tests conducted on new FBE samples include cure by differential scanning calorimeter (DSC), porosity, cathodic disbondment, thickness, hot water adhesion, dry adhesion and flexibility tests. In the case of samples taken from both sites, only thickness, porosity and DSC analysis were conducted. The other tests were not relevant for this evaluation or were not practical to perform. The tests were conducted as per Canadian Standards Association (CSA) Specification Z.245.20-027. Results are given in Table 2. ***P&GJ***

Acknowledgement:

Based on a presentation at NACE Corrosion 2006.The authors express their gratitude to Martin Salazar, DuPont Powder Coatings, for his assistance in FBE sample analysis.

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	TEST		
1	DSC	**Section A**	**Section B**
	Sample not heat treated	Tg_3 = 90.48ºC Tg_4 = 116.04ºC ΔTg = 25.56ºC	Tg_3 = 94.77ºC Tg_4 = 116.92ºC Δ Tg = 22.15ºC
	Sample heat treated	Tg_3 = 101.19ºC Tg_4 = 116.02ºC ΔTg = 14.83ºC	Tg_3 = 105.49ºC Tg_4 = 116.63ºC ΔTg = 11.14ºC
2	Thickness	24-25 mils (600-625 microns)	11-12 mils (275 – 300 microns)
3	Interface Porosity Cross Sectional Porosity	Rated – 1 Rated -2	Rated – 1 Rated - 2

Table 2: Test Summary — FBE sample Homegard 100-Collected from pipe.