Advancements in the Abrasion Resistance of Internal Plastic Coatings

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For more than 60 years, internal plastic coatings have been used for corrosion protection on tubing, casing, line pipe, and drill pipe. One of the historied concerns with the use of these coatings is the threat of mechanical damage and subsequent corrosion. Applicators have relied solely on enhanced surface preparation and adhesion to ensure minimal exposure of the substrate. Several materials have been developed that offer abrasion resistances up to 20 times greater than what has previously been available. This article outlines the development of these products including the different chemistries used and the material's abrasion resistance.

In the development of abrasion-resistant internal plastic coatings, one must first identify the possible abrasion mechanisms that could occur for these applications. Three main types of abrasion are found on the internally coated tubular surface: wireline abrasion, flowing solids abrasion, and large body abrasion.

Interaction between a wireline and a coated surface leads to a cutting action. Film penetration can be quick, exposing the steel to the well environment. It has long been understood that this minimal area of exposed steel would not lead to accelerated corrosion because the surface area ratio of the anode to cathode is very small.[1]

A second type of abrasion is from the erosive effects from flowing solids interacting with the pipe wall. Solids contained in process flow will cause impact as well as general abrasion. The internal coatings can possess a surface finish much smoother than either carbon steel (CS) or 13% chrome. This lower surface roughness will reduce the turbulence (shear) at the surface, reducing small particle interaction and impact.

A third type of abrasion is large body abrasion, in which wear is associated with a coiled tubing run or rod or beam pumping production. The abrasive force from this interaction tends to be spread over a much larger area and, therefore, the rate of penetration tends to be much slower than wireline abrasion. In sucker rod pumping wells, in conjunction with the direct wear abrasion from the constant cycling of the rods up and down the well, there will also be impact on the coated surface from the impact of the rod against the pipe wall. A coating material used in this application will achieve a higher level of success if it possesses both abrasion resistance and impact resistance.

Measurement of Abrasion Resistance

Several laboratory tests were used to determine the abrasion resistance of polymeric coating systems. In one test, ASTM D4060,[2] a flat coated panel of known weight is rotated under CS-17 abrasive wheels with a 1-kg load for 5,000 to 10,000 cycles.

The coated panel is then reweighed to determine how many grams of coated material were abraded away every 1,000 cycles. While this provides a comparable value, the fact that different coating materials have different densities can yield erroneous comparisons. A second allowable recording method is to measure the thickness of coating material, in mils or microns (10^{-6} m), that is lost for every 1,000 cycles. This method provides for a comparison of different coating materials and their abrasion resistance.

Previous work compared two coating materials, an older epoxy phenolic coating and a modified epoxy phenolic coating.[3] The modified epoxy phenolic coating contains an inorganic filler package to enhance the abrasion resistance. During this completion work, there were a total of 17 frack-pack completions in which hydraulic fracturing (frack) fluid (viscous fluid containing either sand or manufactured solids) was pumped through the internally coated pipe at velocities approaching 17.07 m/s (56 ft/s). More than 907,184.7 kg (2,000,000 lb) of frack fluid were pumped and over 41,452.4 m (136,000 ft) of wireline run through this string. As can be seen in Figure 1, the original epoxy-phenolic coating (greenish-brown in color) was abraded down to bare metal in a high erosion zone. The modified epoxy phenolic coating (blue-green in color) lost ~12% of its total film thickness in the same area.

These field results indicate that positive results with the Tabor Abraser[3] testing yielded positive results regarding the materials' ability to reduce the effect of abrasion in the field (Table 1).

ASTM D968[4] has also been utilized to quantify the abrasion resistance of various oilfield coatings. In this test, silicon carbide (SiC) is used to test the erosion/small-body impact resistance of the coating system. The abrasive is allowed to free-fall onto the coated surface of a metal coupon that has been secured at a 45-degree angle. The test determines how many liters of abrasive it will require to completely penetrate the coating surface and expose the substrate. Results are reported in liters of abrasive per mil of coating removed.

It is important also to understand the flexibility and impact resistance of the material to determine how it will handle large body impact in the presence of abrasion, such as in rod pumping applications. When considering the impact related to rod pumping applications, current tests do not generate relevant results. Instead, the flexibility of the coating has been shown to be a better indicator of performance in these applications.

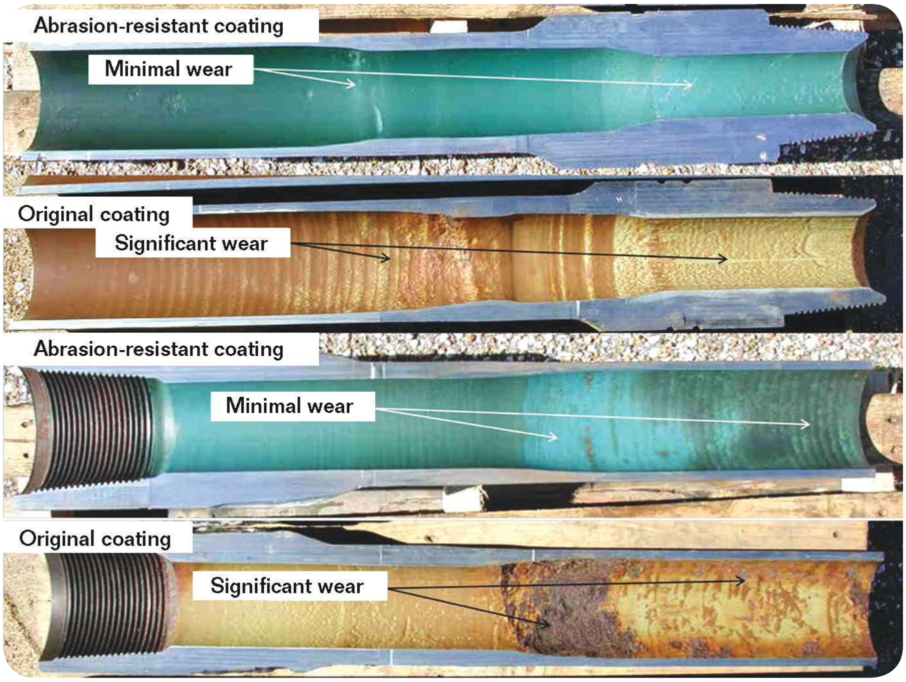

FIGURE 1 Sections of pipe utilized in SPE 77687 comparing abrasion resistance in the same completion environment.

By comparing these test results for different coating systems, it can be determined which one will have the greatest level of success in the various types of abrasive environments. Table 2 shows the parameters for each of these systems including the applications in which they are historically used. Table 3 outlines and compares the results for popular internal coating systems vs. the recently developed materials that have been designed for greater abrasion resistance.

Field Performance

Case History 1

In this case, an operator completed its production wells utilizing Grade L-80 CS[6] on the bottom half of the well and 13% chrome on the upper half. The bottom hole

TABLE 1. SOURCE COMPANY-GENERATED TABER ABRASER VALUES FOR COATINGS TESTED IN SPE 77687[3]

Coating	Taber Wheels Used	Taber Abraser mg/1,000 Cycles	Magnitude of Improvement	Taber Abraser mils/1,000 Cycles	Magnitude of Improvement
Epoxy phenolic	CS-17	67	—	0.6	—
Modified epoxy phenolic	CS-17	9	7.4X	0.18	3.3X

TABLE 2. COATING SYSTEM PARAMETERS

Coating System	Maximum Temperature (°F/°C)	Applied Thickness (µm)	Primary Usage
Phenolic	400/204	127-203	High-temperature/pressure production
Epoxy novolac	400/204	152-330	Product/injection tubing
Epoxy phenolic	400/204	127-229	Drilling/completions
Epoxy	225/107	254-508	Product/injection tubing and line pipe
Modified epoxy phenolic	400/204	127-229	Drilling/completions
Novolac	300/149	254-457	Production/injection tubing
Phenolic novolac	350/177	152-330	High-temperature/pressure production/injection tubing
Modified epoxy	225/107	254-508	Product/Injection tubing and line pipe
Modified novolac	300/149	178-381	Production/injection tubing

TABLE 3. LABORATORY RESULTS FOR COATING MECHANICAL PROPERTIES

	Tabor Abraser Test Values			
Coating System	Mg Lost /1,000 Cycles	Mils Lost /1,000 Cycles[A]	Falling SiC L/mil of Coating[B]	Flexibility (%) Elongation
Phenolic	57	0.5	3.4	1
Epoxy novolac	36	0.5	6.8	1
Epoxy phenolic	67	0.6	6	1
Epoxy	53	0.7	14.9	>6
Modified epoxy phenolic	11	0.18	6	1
Novolac	28	0.38	12	1.5
Phenolic novolac	7	0.065	7.2	1
Modified epoxy	5	0.025	14.9	>6
Modified novolac	2.5	0.01	N/A	1

[A]Allows for comparison between materials with different densities.
[B]A higher number indicates an improved ability to withstand erosion/impact abrasion.

temperature for these wells averages 215.5 °C (420 °F) with a flowing tubing pressure of ~2,000 psi (13.8 MPa). The carbon dioxide (CO_2) concentration ranged from 18 to 22%. At this temperature, there was insufficient liquid water to cause corrosion in the bottom section of the well. The temperature at the metallurgy transition depth is ~160 °C (320 °F). A phenolic novolac coating system was used in an L-80 CS tubing string in place of the 13% chrome tubing. The wells in this field required numerous wireline interventions. Through Well #1, there were 18 wireline runs and through Well #2, there were 33. At the time of this writing, the phenolic novolac coating system is still performing in the well.

Case History 2

Rod or beam pumping wells offer a unique challenge to providing adequate corrosion protection because of the dynamics of the system. Abrasive wear coupled with impact can make many standard corrosion treatment methods ineffective. A highly deviated rod pumping well experienced premature tubing failures from excessive rod wear. This was a Christmas tree well producing ~30 to 35 bbls (4,770 to 5,565 L) of oil and 820 to 840 bbls (130,380 to 133,560 L) of water per day. Rod guides were not employed to minimize wear. A variety of coating systems (including ceramic-filled coatings, nanocoatings, nylon coating, and penetrants) had been field trialed in this well and yielded a maximum tubing life of less than six months.

A modified epoxy coated tubing string was installed in November 2009 and has been successful in dramatically extending the life of the tubing string without the use of rod guides. The tubing and coating lasted 22 months in this application before being pulled and rerun in another application, where it continues to provide corrosion and abrasion protection.

Conclusions

Internal tubular coatings have been susceptible to mechanical damage that could expose the substrate to the corrosive nature of the production or injection fluids. Advancements have been made in both filler materials as well as resin chemistries that have been shown to increase the abrasion resistance of these coating systems by as much as 50 times. These abrasion-resistant systems have proven themselves to perform well when subjected to mechanical intervention such as wireline and coiled tubing, abrasive solids flow such as fracking or the production of sand, and abrasive wear in conjunction with impact forces typically seen in rod-pumping applications. These new coating systems can reduce well construction costs when compared to exotic alloys, as well as reduce production/injection downtime.

References

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