NEW ADVANCEMENTS IN THE USE OF INTERNAL PLASTIC COATING FOR ENHANCED OIL RECOVERY

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ABSTRACT

Past field history has proven the effectiveness of internal plastic coatings as a primary tool for the control of corrosion in secondary and tertiary recovery programs. In recent times, new coating materials have been developed that have been found to enhance the previous performance of coatings by providing materials with greater flexibility and impact resistance.

This paper discusses the basics of these new materials as they apply to the various corrosion mechanisms found in enhanced oil recovery. In addition, current industry standards for the application of internal plastic coatings is discussed in detail, including recommended field handling procedures.

INTRODUCTION

Coatings prevent corrosion primarily by restricting the availability of water, oxygen, and ionic materials to the metallic surface underneath by acting as a barrier material. In addition to forming a barrier, a coating may contain other components to further prevent corrosion; for example, corrosion inhibiting pigments. These pigments contribute strength to the coating and can be made to regulate the acidity of the substrate surface and, therefore, retard corrosion for which acid conditions are desired. In addition, the surface of the topcoat can be resistant to bacterial growth preventing corrosion from the penetrating acid byproducts of the bacterial metabolism.

The application of internal plastic coating to oil field pipe has also been found to reduce the friction coefficient of the pipe surface by approximately one half at normal design flow rates. The Hazen-Williams "C" factor for new bare, seamless, steel is 100. Pipe with corrosion, scale, or rust will be lower accordingly, while plastic coated pipe is generally considered to be 150. In small diameter pipe, 1.900 inch through 4.50 inch OD, this represents a flow improvement between 15 to 25% at a given pressure.

The resin system utilized in a coating system that allows for increased flow rates also aids in preventing the adhesive-like characteristics of paraffin and scale from forming on the pipe surface. As the adhesion is reduced, they are then allowed to remain in the fluid flow and transported from the tubular.

As one can see, the use of internal plastic coatings can and have been offering the engineer many economic benefits when they are utilized in secondary and tertiary recovery projects. Recent studies have shown the use of phenolic and epoxy-phenolic coatings in CO_2 injection to increase the life of tubing ten-fold. However, examination of the tubular after it has been removed from the well, typically finds the phenolic coatings, which by their very nature are fairly brittle, have been severely damaged by mechanical abuse during installation or subsequent workover of the well in which they were initially placed. The damage is normally found within two feet from either end and was caused by the tongs or lack of the use of tongs, slips, and stabbing damage. In an attempt to reduce this abuse that can shorten the expected life of coating in water and CO_2 injection wells, the coating manufacturer has developed new materials to provide a coating that has greater flexibility and impact resistance than the coatings utilized in the past. In addition, the coating applicators and oil companies have been working much closer with field crews to better educate them on proper procedures for handling coated pipe.

COATING MATERIALS IMPROVEMENTS

Historically, internal plastic coatings have been primarily based on the use of the phenolic resin, a high bake thermosetting plastic. The phenolic resin was desired because of its temperature stability up to 400°F and its chemical resistance to most ionic salts, acid gases, and corrosives found in oil and gas production today. By its very nature though, the phenolic resin was brittle and subject to abuse that would especially reduce its full potential in water and CO_2 floods.

In developing new coating systems for improved flexibility and durability, the researcher must utilize materials with lower temperature resistance and materials that offer chemical resistance to more specific applications, versus a variety of conditions than do the phenolics. The resin systems that were selected were the epoxy and nylon materials. These resins, when properly formulated, were found to offer excellent corrosion resistance to water, oxygen, CO_2, and trace levels of H_2S up to temperatures in excess of 200°F (93°C), depending on the well conditions.

The effectiveness of epoxy resins, for preventing corrosive decay in water and CO_2 environments, is the result of using specific epoxy resins to provide a high degree of chemical cross linking. Epoxy coatings are available in three general forms; oil modified, chemically hardened, and high bake. The oil modified varieties are not suitable for oil field service. They are commonly known as epoxy esters that typically contain a drying oil, e.g. linseed, limiting the material's resistance to strong exposure. Chemically hardened epoxies utilize an organic amine to act as a curing agent, producing a high molecular weight thermosetting plastic after several hours reaction time following applications. Amine cured epoxies provide good solvent and acid resistance to 150°F (66°C). High bake epoxies, due to their curing mechanisms, non-amine, possess a higher degree of cross linking, providing greater chemical inertness. This type of epoxy offers better resistance over standard epoxies due to improved toughness and flexibility, vapor permeation resistance, and temperature stability. In addition, for continuous immersion, coatings are sensitive to the permeating forces of water. This effect can be further aggravated by temperature differences across the film. It is, therefore, necessary to achieve the highest cross link density possible to block the water molecule from moving through the coating film. Only the high bake epoxy can best meet this cross linking requirement.

Deviating from the normally used thermosetting plastics, a nylon thermoplastic polyamide, when properly formulated with a specific primer system has been found to offer many advantages over the typical thermosetting systems. Most of the commercially available nylons are synthesized from the diabasic acids and diamines or from the amino acids. Since there are many nylon materials available today, a particular material had to be formed to provide the needs of injection service, i.e., low water absorption, high flexibility, and good chemical resistance. This was obtained by lowering the number of polyamide groups while maintaining the same molecular weight, to reduce the water absorption of the film; and secondly, to alter the density of the material to allow for maximum geometric flexibility. This produced a nylon coating with a relatively low density that was extremely flexible and less liable to break on impact. It was also found, that this material was very stable, had good abrasion resistance, and had excellent chemical resistance except to strong acids, greater than 15% HCl. However, thermoplastics are softened by heat and do have a measureable melting point, therefore, they can be very temperature sensitive.

Even with the improved durability of these new materials, the success level of high bake epoxy and nylon coatings is still dependant upon the environmental conditions, application process, and proper care and handling of coated material.

ENVIRONMENTAL CONDITIONS

The waters utilized in the petroleum industry, for injection and that which may be present in produced fluids, may affect the unprotected steel tubular in two manners. First, the presence of various ionic salts, bacteria, and free oxygen in the fluid may cause selective attack of the metal substrate. Secondly, the water may be supersaturated with various carbonate and sulfate compounds causing the deposition of scale.

The presence of soluble salts in the water may cause the fluid to be more or less corrosive depending upon their concentration. In general, under dynamic conditions a saturated salt solution would be less corrosive than a fresh water system due to the lack of dissolved oxygen. However, as the salt concentration increases, the electrolyte becomes more conductive allowing for the anodic and cathodic areas of the corrosion cell to be further apart.

Dissolved oxygen may be the major cause of corrosion failure in injection tubing. Oxygen can affect the steel tubular in three ways. First, oxygen acts as a depolarizer. It removes electron accepting hydrogen ions from the cathode which could build up to slow the corrosion process. Secondly, oxygen can directly attack the metal at the anodic sites. Finally, oxygen environments favor the formation of concentration cells which will cause localized corrosive attack to develop, e.g. pitting corrosion.

There are two types of bacteria found in a water system that may cause corrosive attack. Sulfate reducing bateria, that thrive in the absence of oxygen, may cause hydrogen sulfide to form in the water causing corrosion. Secondly, aerobic bacteria, that function in the presence of oxygen, which include the various iron bacteria that can result in unwanted accumulation of iron oxide solids.

There are two main factors that determine scale formation. They are the degree of supersaturation and the rate of crystallaization which is determined by the degree of supersaturation, the nature of the structure, and the nature of the fluids. Scales commonly encountered in the oil field are gypsum ($CaSO_4 \cdot 2H_2O$), calcite ($CaCo_3$), anhydrite ($CaSO_4$), barium and strontium sulfates ($BaSO_4$ and $SrSO_4$), and iron compounds. The presence of various scale forming cations, (e.g. calcium, barium, or strontium) and anions (e.g. carbonate or sulfate) at a supersaturation level may cause precipitation to take place resulting in scale. As this scale deposits on the unprotected steel surface, isolated corrosive attack may occur beneath the scale as well as flow restriction through the tubular.

Another common material used in enhanced oil recovery is Carbon Dioxide (CO_2), a miscible gas that often times is utilized in an injection program where water and CO_2 gas are alternated for various periods of time. This type of program is more commonly known as a WAG System (water-alternating-gas).

Carbon dioxide gas is non-corrosive in the absence of water. When moisture is present, from the water cycles in the WAG system, the CO_2 gas reacts with it forming carbonic acid. This carbonic acid causes a reduction in the pH of the fluid, making it extremely corrosive to steel. Several of the factors that govern the solubility of CO_2 are pressure, temperature, and the composition of the water. As the pressure increases so does the solubility of CO_2, temperature decreases the solubility, and many dissolved minerals may buffer the water (prevent pH reduction). In general, with the pressures, low temperature, and the water quality typically used for injection, CO_2 injection is a very corrosive situation.

COATING APPLICATION

An important determining factor in the performance of any coating is proper application to the internal surface of the pipe. Thermosetting or thermoplastic coatings, regardless of their specific chemistry, have a number of common characteristics in their properties involving application. They must be applied to clean metal in order to have adhesion. Metal cleaning typically involves a "thermopickling" process that provides for a uniform heating of the steel tubular to oxidize hydrocarbons and dry the pipe (725° F/385°C). Following this procedure, the tubular undergoes an abrasive blasting to "white metal" with a suitable abrasive to allow for a roughening of the metal surface to an average anchor pattern of 1.0 to 1.5 mils. Remaining dust and abrasive particles are then removed by blowing clean dry air through the tubular. Following abrasive blasting, all tubulars are visually inspected from both ends with a high intensity light to insure proper cleaning.

Since epoxy and nylon coatings are both powder applied, the application procedures will be very similar. Initially, a specifically formulated liquid primer coat, approximately 1 mil in thickness, is applied to the steel surface, by use of a lance and hydraulic pressure, to increase the adhesive characteristics of the powder. The specific primer system utilized will depend upon the powder coating being applied. The primer is then intermediate baked, typically in a conveyor oven to provide a uniform heating of the pipe, to achieve two purposes. First, to flash off the solvents in the liquid primer and secondly, to bring the pipe up to cladding temperature, the temperature at which the specified powder coating will melt and adhere to the primer. After proper heating, the powder material may then be applied in a one step application by use of a vacuum system, drawing a charge of powder material from a fluidized bed through the tubular as it is rotated at a constant speed to control thickness. As the powder contacts the hot metal surface, it melts and then begins to harden or gel into a more rigid form to prevent runs and sags from occurring. The epoxy system, which is a thermosetting plastic, then undergoes a final bake at an elevated temperature to cure the coating and provide for proper cross linking of the resin. The nylon coating, a thermoplastic, does not require final baking.

Final inspection of the completed product is then carried out, including a complete visual examination of every tubular coated and thickness readings being taken on both ends to insure compliance to the specification. In addition, each joint of pipe is then holiday tested. For thick film coatings typically at 2000 volts DC current, to check for any discontinuity in the coating film. For water and CO_2 injection, the coating should be 100% holiday free, including all areas that will be exposed to the injection fluids.

HANDLING AND INSTALLING PLASTIC COATED TUBULARS

Just as proper application is essential to coating performance, correct handling and installation procedures must be followed to insure maximum life from a coated tubing string. Most premature failures of coating have resulted from improper handling. Care and handling can be basically broken down into three areas; transportation and storage, at the wellsite, and subsequent well stimulation and treatment after installation.

Upon leaving the coating plant, most plastic coated pipe is transported by truck. When transported by truck, a flat bed trailer must be used with at least three bolsters between each layer of pipe, with the bolsters being aligned vertically above the previous layer to provide even support. The load should then be tied down in such a manner as to prevent any shifting, bending, or movement of the pipe. All pipe should be transported with closed end thread protectors on both ends, preferably made of plastic or a plastic lined steel (composite) protector.

For storage, the pipe should be placed on at least three racks or wooden sills evenly spaced to support the pipe 18 inches off the ground. To stack the pipe, wooden bolsters should be placed between each layer, directly above the pipe racks, with each layer being blocked to prevent shifting. When movement of the pipe is required on the racks, bars or similar objects should never be placed in the pipe I.D. If thread protectors have come loose, the threads and coating should be inspected for damage and the thread protector reinstalled prior to any movement. If the pipe must be drifted, the yard personnel must use a wooden, teflon, or plastic drift to prevent damage to the coating.

When running the pipe, it is important to select the best tools that are available, especially in the selection of slips, power tongs, back-up tongs, and slip-grip elevators. Equipment with as much surface contact as possible to the pipe; e.g. full wrap around tongs, should be used. When the tubing is lifted onto the rig floor, the pin end thread protector has to be in place to protect the threads and the coating that covers the chamfor and typically the first two threads. It will be removed just prior to stabbing for make-up.

When making up internally plastic coated pipe, a certain amount of judgement must be used due to the coating that is applied to the pin end and in the "J" area of the coupling. For stabbing, a plastic stabbing guide must be used to guide the pin end directly into the middle of the coupling, to eliminate any contact of the pin end with the top edge of the coupling. Due to the coating in the threads, initial make-up will normally produce higher than normal torque values, but subsequent make and breaks of the same connection would be more in line with published torque values. For this reason, initial make-up of internally plastic coated pipe should first be made by position, plus-or-minus one thread from hiding the last scratch to insure coating to coating overlap of the pin end with the coupling, while monitoring the torque. Keeping in mind that maximum torque values may be observed until the coating is removed from the threads.

Well stimulation, when carried out, must be done with caution and well planned. Prolonged exposure of the coating to acid and many organic solvents, especially at elevated temperatures, could result in severe damage to the coated string. Complete flushing of the tubular to remove any acid or solvent must take place immediately after the treatments, keeping in mind that it must be of such a volume to completely remove any residual acid or solvent from the coated surface.

Any wireline work should always be done at reduced speeds of 100 feet per minute or less, with a stiff line always being maintained and weight on the indicator at all times. It is common knowledge that most of the damage caused by running wirelines is caused by the tool impacting the coated surface. For this reason, tools should be selected that do not have sharp edges and should be so designed to reduce the effects of any sharp impact to the coating.

CONCLUSION

When a major operator in West Texas can place plastic coating, that was damaged by mechanical abuse during installation, in a CO_2 WAG well, and increase the life of the tubing string from 3 months to 31 months, the economics of coating for corrosion prevention in this type of well have more than justified the use of coatings. Now, with the more durable epoxy and nylon materials available, operators are expecting and have already seen less damage to their coated tubulars during installation, which will provide longer life and greater economic benefit. However, even with these more durable materials, to insure maximum effectivensss of the coating system, proper application, installation, handling, and care of the coated tubulars still should be followed.

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