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A PROCESS FOR LINING OILFIELD PIPELINES

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ABSTRACT

Internal corrosion has long been of major concern to pipeline owners, having spent millions of dollars and countless man-hours combating its destructive effects. Pipeline failures, due to internal corrosion, have produced environmental and legal issues that have resulted in huge fines and judgements, creating even greater concerns about its ambiguous nature. Over the years, a number of technologies have been introduced to deal with the variety of corrosion problems that exist in oilfield pipelines. One such option is a 50 year old technology known as in-situ coating. The in-situ coating process is a relatively simple procedure, whereas, the internal pipe wall is thoroughly cleaned, either by means of abrasive blasting or by a system that combines progressive pigging and chemical cleaning. This is then followed by the application of several coats of a suitable protective coating. The most common coating used is typically a high performance epoxy. The process is unique, whereas, pipeline pigs, instead of conventional spray equipment apply the coating.

The objective of this paper is to address the overall process of in-situ coating, which includes; cleaning options and effectiveness, coating selection and application, its limitations and residual benefits and the pipeline owners or operators involvement.

INTRODUCTION

Pipeline companies continue to look for maintenance-free technologies to control internal corrosion. In-situ coating is viewed by some as a maintenance-free technology, whereas, a protective barrier is placed between the pipe wall and the corrosive environment. However, some minimal maintenance is recommended, such as periodic pigging, along with a minimal inhibition program. Pigging may be used to maintain the efficiency, should deposits and liquids effect flow, when left to settle in low-lying areas. The use of inhibitors will provide additional assurance, should the coating become damaged due to improper pig use.

In-situ coating has proved equally effective in new and existing pipelines, both onshore and offshore. When applied to new lines, the system is an excellent first line of defense, preventing corrosion before it has a chance to start. However, in-situ coating is most commonly used when few options remain and total line replacement appears imminent. Rehabilitation of a pipeline with the insitu coating process, will normally cost 30% or less, than total pipeline replacement, depending on condition of the pipeline, number of lines to be coated, whether onshore or offshore or other location adversities. There has been articles written, indicating that properly applied coating could extend pipeline life as much as 40 to 50 years, depending on environmental conditions and minimal supplemental maintenance. The major advantage of in-situ coating, over other rehabilitation processes, is the ability to rehabilitate many miles of pipe, without having to cut or segment the pipeline. This is essential when working offshore. One major disadvantage, is that the unit price can be very expensive for pipelines less than three (3) miles in length. This is due to the base amount of equipment, materials, and personnel required for the process. The pipeline diameters are not extremely restrictive, although, most lines that have been in-situ coated range between the nominal size of 4" and 30".

The most obvious use of in-situ coating is to combat the ravages of internal corrosion; however, it has also been used solely for its residual benefits, such as, reducing friction to flow and maintaining product purity. Some pipelines have experienced an increase in efficiency after coating of 6% or more. In-situ coating is also a viable option when a pipeline requires a change in service and future product purity is essential, as seen in an example of changing a crude oil line to jet fuel service.

When a pipeline company selects a pipeline for in-situ coating, the owner and its applicator must first investigate all aspects of the pipeline to assure its candidacy for the in-situ coating process. Once determined that the pipeline is in fact a candidate for in-situ coating, a thorough understanding of the process and its variables is to be developed. A cleaning method will be determined and a suitable coating will be selected. It is also strongly recommended that the proposed coating be subjected to a laboratory performance test, according to NACE and the coating manufacturer's recommended practices and then tested for exposure to simulated pipeline environments before field usage.

DESCRIPTION OF THE PROCESS

1. In-situ Cleaning:

Surface preparation is critical to the success of any coating project. The in-situ coating process provides two different and distinct methods of cleaning the pipe wall; the two methods are abrasive blasting and chemical cleaning. Each method is adequate for obtaining the proper surface preparation. The abrasive blasting procedure will typically produce a NACE 1, white metal surface, while chemical cleaning typically is complete at a NACE 2, near-white metal surface. The coating is designed to adhere effectively to either surface, however, over the years; the bulk of the work has been credited to chemical cleaning.

1a. Cleaning by Abrasive Blasting to New Pipelines

It should be noted, that this procedure is most cost effective when performed on new pipelines.

Abrasive blasting is an internal cleaning method that injects hard cleaning particles into a gaseous medium, normally nitrogen or dry compressed air. The gas or air is introduced into the pipeline in a manner to create a turbulent critical flow rate, at an extremely high velocity, which causes the abrasive cleaning particles to impact the internal surface of the pipe wall. The impact of the particles, removes oxides and hard scale deposits, producing a minimum of a NACE 2 finish.

Depending on the pipeline characteristics, such as, diameter, bends and other geometric considerations, a single setup can clean approximately 1/3 of the diameter, measured in miles. Example: (a typical line geometry could be 12" x 4 miles long). A general rule of thumb is:

$$L_{MAX} = \frac{I.D.}{3}$$

The first step in abrasive blasting is the removal of any residual liquids. In a new pipeline, this would require the displacement of any remaining hydro-test water. This is accomplished by running a series of foam swabs, with nitrogen or dry compressed air, until the surface is completely dry.

A blasting head is installed at the launch end of the pipeline. A high capacity nitrogen pumping unit begins flowing high volumes of gas, while the abrasive material is injected into the gas flow. The gas flow provides enough kinetic energy to cause the abrasive particles to make repeated contact with the pipe wall from end to end.

Depending on the pipeline characteristics, abrasive blasting a pipeline to a NACE 1 or 2 can be completed in a matter of hours. The blasting materials can be recovered at the receiving end of the pipeline by simply using a standard covered dumpster. When this procedure is performed on new pipelines it has no environmental impact and all effluent can be easily disposed of.

When all inspection points have been inspected and adequate cleaning and surface profile has been verified, the heads are removed and a standard pig launcher and receiver is installed.

From this point forward, the nitrogen pumping units are normally replaced with large oil-free air compressor, fitted with dehydration units. The dehydration units are capable of producing a dew point of –40° F. Replacing the nitrogen units with air, generally results in considerable cost savings.

A series of foam swabs are run to remove any residue of dust that may have collected on the pipe wall, created from the breakdown of the blasting medium. After running several swabs, 2 to 3 batches of solvent is run through the line between two urethane pigs. Samples of the solvent batches will be collected at the receiver and inspected for any signs of the blasting material.

The final step, before coating, is to run a few wiper pigs, insuring total evacuation of the solvent, which is then followed by a slow dry air purge of the pipeline, until the dew point is stabilized.

1b. **Chemical Cleaning for New or Rehabilitation of Pipelines**

A variety of chemicals and procedures have been developed to deal with the many deposits and scales encountered in existing oilfield pipelines. The chemical-cleaning procedures have been designed to deal with the worst-case scenarios;

The cleaning process begins by displacing all product from the line. Foam pigs are used to batch fresh water through the line. Samples of the effluent is collected at the receiver and analyzed for its content. When paraffin is encountered, solvents are batched between bi-directional pigs to soften and remove all traces of paraffin.

Caustic detergent is batches between foam brush pigs to wash the surface and remove all remaining hydrocarbons and loose deposits. Samples of the effluent is collected at the receiver and tested for solid content and viewed with a black light to determine the presence of hydrocarbons. The line is then flushed with fresh water to remove any trace of detergent.

Hydrochloric acid (HCl) is batched between acid resistant pigs, at a concentration between 15-25%. The acid strength is verified by titration before its loaded at the launcher and tested again at the receiver. When the sample indicates the acid strength has not significantly depleted, and there is no significant amount of solids, the line is considered clean. Pipelines onshore can be visually verified by means of in-line inspection spools.

An inhibited water solution, with an adjusted pH, is batched between pigs to buffer the surface to a neutral pH and to remove all chlorides produced by the hydrochloric acid runs. It has been determined that the chloride content must be below 300 PPM before proceeding.

A phosphate treatment is prepared by mixing phosphoric acid with water, at a concentration of approximately 5%. This treatment is viewed as the final cleaning phase, and will aid the coating in receiving its maximum adherence to the pipe wall.

One or two runs of the inhibited water solution are needed to buffer the low pH of phosphoric acid solution. The samples collected at the receiver, should indicate a slightly basic pH.

A solvent batch is run to insure that all moisture is sufficiently removed from the pipe wall. This final phase will be followed by a dry air purge until the dew point at the outlet equals the dew point at the inlet. Specifications require a final dew point of 10° below substrate temperature, although a much lower dew point can be anticipated.

2. Coating

The coating has been pre-selected and tested to operate sufficiently in its operating environment. It must have an adequate pot-life to allow for enough time to load the batch into the pipeline, run the length of the line and recover the excess coating at the receiver. In long lines of 20 miles or more, a 6 to 8 hour pot-life is needed. Coatings used in the in-situ coating process normally have a solid content in the range of 70-85%, with a typical viscosity of between 95-120 kreb units.

Most coating projects are designed to apply approximately 2 to 3 mils of coating per coating run, and normally require 3 to 4 coats to achieve the typical contracted dry film thickness (DFT). The drying time between coating runs is typically 16 to 24 hours.

The coating pigs will be modified, just before coating, to allow for the wall thickness of the pipeline and to allow for the type of coating to be used. Each pipeline has its own unique characteristics, which create some ambiguities with the first coating run. Normally, the first coating run will target a mil thickness just thick enough to fill the surface profile.

Each coat of paint is loaded, using high volume pumps, between the two modified pigs. Once the coating is pumped between the pigs, all air is purged from the coating batch. The movement of coating batch is controlled by the differential pressures exerted to each end of the batch. Depending on the diameter, wall thickness and length, the run speed will be in the range of 8 to 10 feet per second.

When the excess coating arrives at the receiver, it is removed and is normally placed back into its original container. The amount of coating received is recorded, with the difference between the amounts loaded and received, indicating the applied mil thickness, as based on the manufacturer's theoretical spreading rate. This is the accepted method of determining the applied mil thickness on all offshore pipelines, since the area at the launcher and receiver is rarely representative of the actual applied mil thickness. It must be understood that the in-situ coating process is an extrusion application, whereas, the speed of the coating batch, less than its normal run speed, will most likely produce a somewhat lower mil thickness. This is also true of the slow speed at which the coating can be removed from the receiver. It is recommended to install additional piping, of approximately 40 feet to each end of the pipeline, to allow for the speed variance. Onshore pipelines will normally have at least one inspection (spool) point, located at or near the middle of the pipeline. The inspection points provide a location, in which typical quality control tests can be performed.

ECONOMICS AND ADDITIONAL BENEFITS

Although the in-situ coating process is primarily used to prevent corrosion, other benefits are derived from the process, providing additional economic justifications. The following information was obtained from a major gas transmission company, with extensive in-situ coating experience completed within its own offshore pipeline system.

Internal in-situ coating costs for a single offshore pipeline will typically represent approximately 15% to 25% of the estimated replacement cost, not including marine vessel support.

Repair Benefits:

Example: 5.3 miles of 16", had four internal corrosion leaks in 1 year during 1979. The pipeline was scheduled for either replacement or in-situ coating. It was elected to in-situ coat the line, which proved to be economically beneficial, in that no additional internal corrosion leaks have occurred to date, and service was not interrupted for any appreciable amount of time.

In-situ coating reduces friction to flow:

In-situ Coating reduces friction to flow by smoothing the internal pipe roughness factor, thus pipeline efficiency can be enhanced as much as approximately 6% on a loaded flowing pipeline. Internal girth welds are also smoothed resulting in less chance for corrosion at these sites and additional increased flow efficiency.

The chemical and mechanical cleaning before the coating is applied, alone, can contribute significantly to reduce plugging material build-up and reduce flow drag in pipelines. The application of the smooth internal pipe coating enhances flow velocities in addition to flow improvements produced by the cleaning process.

Flow Efficiency Benefits:

At 95% or more of line pack, a 6% flow efficiency improvement on a 12" In-situ coated wet gas pipeline 15 miles in length and flowing 15 mmcf/d has equated to an increased throughput generated revenue of:

(15 mm X .06 = 900 mcf/d) X $2.10/mcf (transportation) = $1,890 additional revenue per day

$1,890 X 365 days/yr. = $689,850 annual additional revenue

Five-year efficiency benefit:

$689,850/yr X 5 yrs = $3,449,250 ($3.5 million US dollars)

Other benefits include; compression fuel consumption savings, reduction in inhibitors use by 50% or more, and reduced pig runs and pig cost.

In-situ pipeline coatings control corrosion. Supplemented with continuously applied corrosion inhibitors and on-stream pigging, this type of coating offers a very effective and economical means of offshore internal corrosion control in wet gas pipelines.

CONCLUSIONS

The in-situ coating process provides a low maintenance corrosion control option, where conventional methods, such as, frequent pigging and inhibition fail to provide adequate protection. A thorough understanding of the cleaning process and proper coating selection is key to a successful job. The process is cost effective and can certainly add years to new and existing pipelines.

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