An Economic Case for Composite Lining of Oilfield Tubulars

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Abstract

Lining and coating of oilfield tubular goods have long been common solutions to downhole tubular corrosion problems in oil and gas operations. Thermoplastic linings and spray-coated resins have been replaced in numerous applications recently with filament-wound composite materials. Notably, the introduction of Fiberglass-Epoxy Resin liners in downhole and surface steel tubular goods has provided opportunities for continuous operation in corrosive environments under higher temperatures and greater volumes of corrosive substances. Increased capabilities of fiberglass-lined tubulars in deep corrosive gas wells, for example have given operators greater flexibility by providing less-expensive options to costly alloy steel production tubing. These were previously perceived to be the only choice. New products have emerged that will tolerate temperatures in excess of 300" F and high concentrations of H_2S and CO_2 amongst other corrosive gases and liquids. In addition, operators of disposal facilities are saving capital expense by disposing waste gas through FG-lined tubing into depleted sands and carbonate reservoirs in lieu **of** constructing elaborate treatment plants to remove corrosive waste products.

This paper will examine the long-term economic benefits of FG-lined tubular goods vis-a-vis various alternatives- typically less expensive methods such **as** Internal Plastic Coating (IPC) and tubulars lined with cement products as well as with Polyvinylchloride (PVC) and Polyethylene products. Additionally, comparative examples are presented where corrosive gases are being produced through alloy steel in high-temperature applications at production facilities. Finally, case histories of both high-temperature gas production and large volumes of low-pH waste products are being disposed are presented.

Introduction

Corrosion damage to capital assets inflicts a high negative impact throughout nearly every industry in business today. NACE estimates annual corrosion costs to effectively remove $300 Billion per year from U.S producers alone. About $150 Billion of these costs can be prevented by various forms of corrosion engineering (1). It is estimated that tubular corrosion alone costs the oilfield industry hundreds **of** millions of dollars per year. These figures represent a direct negative impact on total ROI. Although any cost can be construed as negative, the economic effect of downhole corrosion is especially dire because it is largely preventable. In addition to the direct costs that corrosion has on the industry, indirect costs associated with Health, Safety and Environment (HSE) and compliance with regulations made necessary through shortsightedness and poor planning weigh heavily upon the industry.

Prevention of the costs of damage associated with downhole corrosion can be achieved through:

- Design Issues
- Material Selection
- Chemical Treatment
- Construction of Corrosion Barrier

The corrosion barrier is the simplest and arguably the most effective process of these alternatives. Composite technology has evolved rapidly to provide economically viable solutions to corrosion in the form of a barrier between the corrosive elements and the steel in service.

Fiber-reinforced thermosetting or thermoplastic matrix materials define composites. The introduction of composites into the oilfield has yielded the opportunity for operators to select lightweight corrosion-resistant alternatives to high-cost alloy steel in many instances. Applications include onshore (pipelines, tanks and storage vessels), offshore (injection lines, structures and flowlines) and downhole (composite tubing and lined tubulars). Lined tubulars consist mainly of steel tubing with standard oilfield connections lined with Glass-Reinforced Epoxy (GRE) or High Density Polyethylene (HDPE) and Polyvinyl Chloride (PVC). **(2)**

This presentation examines the use of Glass-Reinforced Epoxy composites as a barrier to downhole tubular corrosion. The practice of lining steel pipe with GRE composites has gained wide acceptance over the past 20 years. Technology has advanced to the extent that the production costs of GRE have been lowered to feasibility. Additionally the construction of the GRE material itself has evolved to the point where it is now being manufactured to tolerate increasingly severe environments. Outperformance of thermoplastic products including HDPE and PVC by GRE in high temperatures or the gaseous environments have been strong economic drivers for the manufacture and installation of GRE in lined steel tubular goods. For example, the permeability of thermoplastics to small gas molecules has rendered them largely ineffective in $CO2$ injection service and gas-lifted production. Temperatures in excess of 150° F are outside the capabilities of Polyethylene and Vinyl Chloride materials as well.

Additionally, GRE liners enjoy an advantage as a superior corrosion barrier over less-costly ID coating. Lining of tubular goods has proven to be a preferred solution to ID coating of Urethane and Epoxy-Resin compounds by virtue of the steel surface itself. The roughness of the finished carbon steel product **ID** is such that a completely "holiday-free'' coating can never be completely achieved. Subsequent handling damage to the coated steel product is frequently the cause of corrosion failures where the corrosion surface is the exposed steel beneath impacted coating. GRE lining of steel tubular goods replaces the ID completely and the lined steel tube is inherently holiday-free. The lined tubing is capable of providing trouble-free service in high-temperature, gas-saturated corrosive environments where thermoplastic linings and pipe coatings fail.

Description

Glass-Reinforced Epoxy composite liners are manufactured using a filament-winding process in which continuous strands of fiberglass material are wetted with a proprietary resin compound prior to being wound about a spinning mandrel. The winding is repeated in a helical fashion over a series of repetitions until sufficient thickness has been achieved. The resulting cylindrical tube is subsequently gelled and cured at a high temperature over a period of several hours. The tube is then finished to specification in a series of drifting and planing procedures prior to installation.

Quality measures integral to this process include rigorous control of temperature and curing times during the manufacture of the GRE tubes. Strict monitoring of the epoxy composition is critical in addition to careful measurement of the product dimensions throughout the manufacturing process. Because the product is expected to perform in a variety of harsh environments, periodic testing of the finished product is fundamental to quality control. A representative sample of completed GRE tubes are measured on a periodic basis for other criteria:

- The effectiveness of the curing process is calculated by measuring the glass transition temperature.
- Resin content is verified by weight and percentage using carefully defined procedures.
- Samples are cut and measured for uniform circumferential thickness.

When the GRE-lined tubing is installed by the end user, accommodations must be made to ensure protection of ***the*** coupling area from exposure to the corrosive fluid **or** gas. Historically, the most effective method has been **to** install a rubber compression ring into the coupled area, which upon makeup of the connection is compressed to fill in the "J"-dimension of the coupling **(3).** This completes the integrity of the protective surface inside the tubing string and eliminates contact of the carbon steel with the fluid or gas in transport. The design for this component has proven effective in this application for over **45** years and continues to perform well in every circumstance.

The Need for Protection against Corrosion

Many oilfield processes are detrimentally affected by corrosion. Within the scope of this presentation, four distinct applications involving the use of oilfield tubular products are examined. Injection of produced water into reservoir rock to provide enhanced recovery of hydrocarbons often subject the completion string to harsh corrosive environments. Water flood operations and tertiary recovery involving C02 alternating with water **(W-A-G** injection) provide perhaps the most detrimental of all downhole environments. Disposal well tubulars are commonly adversely impacted by downhole corrosion, especially where corrosive gases (acid gas injection) are combined with produced fluids. Corrosive gas in gas-lifted production is highly detrimental to carbon steel tubular goods. Finally, injection and transportation lines constructed on the surface are often placed in corrosive service where it is especially important to address safety and environmental issues.

Corrosive Environments in Enhanced Recovery Projects

Not surprisingly, most downhole tubular corrosion is associated with the exposure of downhole steel to low-pH environments encouraged by the combination of groundwater with a variety of acid-forming elements. Typically, carbon steel injection tubing utilized in secondary or tertiary recovery is a candidate for treatment to either prevent the corrosive solutions from forming or to construct a barrier against the resulting corrosive fluids. Groundwater from fresh water sources as well as high-saline sources can lead to the formation of acids and solvents by combining with H_2S and CO_2 from either downhole sources, injected fluids, or a combination of both.

Large-scale users of GRE-lined tubular goods are generally involved in water flood and CO_2-flood enhanced recovery. Injection wells and in some cases, production wells in these fields are excellent examples of highly corrosive environments. Most commonly, untreated produced water is used as the source for injection to maintain reservoir pressure. This fluid is quite often high in salt content and has large quantities of dissolved solids. The reaction of carbon steel to high-saline environments is well documented and it is not hard to imagine the effect of exposure to these fluids alone. However, there are additional elements present in produced fluids that can contribute to the deterioration of steel tubing. As the water flood matures, corrosive gases are typically introduced into the injection fluid increasing the likelihood for downhole damage.

CO_2 injection has created perhaps the most severe of all corrosive environments. The procedure used in maturing CO_2 floods is to alternate produced water with CO_2 injection (W-A-G) combining all the necessary ingredients to form carbonic acid. The formation of this acid in constant exposure to downhole tubing will quickly render the injection project unmanageable, as carbonic acid is highly reactive to carbon steel. Well service costs and HSE issues will arise over a very short period of time and lifting costs will rise.

Another benefit of GRE composites presents itself in CO_2 injection at the molecular level. The size of the CO_2 molecule is very small and has the ability to penetrate most thermoplastic materials previously used exclusively as tubular lining products. PolyVinylChloride (PVC) and PolyEthylene are two commonly utilized materials that are easily penetrated by CO_2. Once the gas has penetrated the plastic, the danger of lining collapse becomes imminent upon rapid depressurization of the tubing string. Ultimately the exposure of the gas with the steel will result in a corrosive situation and the costs associated with lining the tubing will not contribute to the life of the project. GRE is an amorphous solid, a unique property that gives the material its far superior resistance to gas penetration. The nature of the GRE composite is such that its molecular structure inhibits the passage of gas through the liner, thereby reducing both dangers of corrosion due to surface exposure and the possibility of subsequent liner collapse upon rapid depressurization of the tubing string. Additionally, the orientation of the glass fibers increases hoop stiffness which gives the liner increased ability to resist collapse.

Disposal of Corrosive Fluids and Gases

Produced fluid being disposed of is typically comprised of salt water and can contain gaseous elements as well. By themselves or in combination with one another, disposal of these compounds quite often requires special corrosion-resistant downhole facilities. GRE composites are the lining materials of choice for a variety of applications. Again, the ability of the fiberglass to resist gas penetration is a fundamental benefit of disposing highly corrosive salt water and various other fluids through GRE.

Acid **Gas** injection is a highly cost-effective method of disposing of waste gases downhole, eliminating the requirement for costly surface treatment facilities. **H_2S** and CO_2 are frequently stripped out of the produced hydrocarbon before entering the sales line. Until recently, these gases were vented to the atmosphere after removal of the acid-forming elements. **As** an incredibly durable barrier to corrosion, GRE linings for tubular goods have given the operator advanced capabilities to withstand deterioration of downhole disposal tubing by these corrosive gases. Compounds consisting of **40-60%** H_2S and 40-60% CO_2 (combined gas products) are being disposed of downhole on an increasingly regular basis through GRE composite-lined steel tubing. In most instances, produced water is injected along with the acid gas on the order of 2000 to 5000 barrels per day.

The oilfield is not a unique environment where corrosion has been stopped by GRE composites as a barrier to corrosion. Industrial waste gas is processed in Wet Flue Gas Desulfurization (FGD) using Glass Reinforced Epoxy composites as conduits between reaction vessels. Wet FGD is the preferred method for removing sulfur dioxide from coal combustion by-products. GRE stack liners are also used increasingly in these processes as a preferred method **to** costly alloy steels (4).

GRE Lining of Production Strings to Mitigate Corrosive Gas Damage

Case histories exist where GRE lined tubulars provided cost-effective prevention of corrosion in high-volume gas-lifted oil production. A majority of IPC-coated tubing failures are leaks in the tubing pins and couplings. The corrosion barrier ring associated with the GRE lining system minimizes the contact of corrosive fluid with the steel tubing and subsequent years of trouble-free production are made possible (5). Additionally, GRE lined steel tubing in production wells can be demonstrated to retard the tubular deposition of paraffin and asphaltenes.

GRE Lining of Surface Tubular Goods

On an increasing basis, surface lines handling corrosive produced fluids and injection fluids are lined with Glass-Reinforced Epoxy. The flexibility and low weight of the composite are attributes that lend themselves very well to this application. An additional benefit of GRE-lined steel tubing over FG (fiberglass) tubing lies in the fact that special bedding does not have to be prepared. GRE-lined tubing can be buried like any other steel product. The bending modulus of the fiberglass liner **as** compared to the lined steel pipe permits the liner to be tolerant of steel pipe bends up to the steel pipe elastic limits. The end user realizes the benefit of the corrosion-free surface provided by the GRE-liner and the strength and durability of the steel. Composite-lined flowlines in excess of one million feet are in service today, most commonly as injection and transportation surface lines. Installations of GRE-lined flowlines have employed threaded tubular connections and welded connections.

The cost of compliance with environmental regulations has been extremely high over the past decade. The potential for damage is well documented when the need for protection against corrosion on the surface has been ignored.

Costs of Well Service Due to Corrosion

In today's environment of diminishing reserves and marginal projects, greater emphasis is placed upon reducing the costs of production. There is now a stronger case to be made for an increase in capital expenditure at the commencement of a project in exchange for lower lifting costs over the project life. The high cost of well service is the easiest to recognize and is likely the most obvious. Additionally, costs that reduce the operating efficiency of an asset include the costs of lost production due to downhole and surface maintenance, **HSE** costs and cost of product replacement. An incremental increase in cost **of** tubular goods constructed using GRE to eliminate the cost of corrosion is a prudent economic measure where project life is expected to surpass the useful life of a lined or coated product of lower quality. This is illustrated in research performed by a North Sea operator as they qualified GRE lined tubulars for water injection service to increase design life from 5 – 7 years to 10 – 20 years.

Workover Economics- Offshore vs. Land Operations

Using the North Sea Operator's example of offshore workover economics, platform workovers have target costs of $3.13m for IPC plastic-coated tubulars with low chrome CRA accessories. This cost is expected to increase by the amount of $330K to employ GRE lined tubulars and much higher chrome content CRA accessories. Higher Chrome/Nickel content accessories are judged necessary due to increased life expectations. Using IPC, the time between workovers **is** judged to be 7 years maximum; therefore the annual cost of each well equals $3.13M/7 years product life = or $0.447M/year. Using **GRE** lined completions, the cost of working over a well is $3.46M. The completion only has to have an additional life of 9 months beyond IPC life to pay out the incremental premium of the GRE lining (marginal cost = $3.46M - $3.13M = $0.33M, $0.33M/$0.447M/year = 0.74 years or 9 months) (See figure 1).

Land-based operations involve considerably lower costs but the relative economics are based on the same model. The cost of an average workover in the Permian Basin, for example, costs between $2500 and $3000. The incremental cost of lining API tubing as opposed to coating with plastic is in approximated at 20%. For a 10000-foot string of 2 3/8 API 8rd tubing, this is an average cost increase of $3600. The tubing now costs **$21, 100**. Again, using an estimation of a seven-year maximum product life for IPC tubing, annual lining cost of the IPC tubing is $1750017 = $2500. If the incremental cost of the GRE tubing = $3600, the economics of this situation indicate that the GRE will pay out after an additional (3600/2500) 1.44 years or approximately 17 months of service. (21,100 – 17500 = 3600, $3600/2500 = 1.44 years) (See figure 2).

Even in the most severely corrosive environments, GRE-lined tubing remains in service and has been abundantly documented in instances well beyond this time frame, numerous in the 15 to 25 year ranges.

Opportunity **Cost** Savings

The preceding examples are perhaps oversimplified to the extent that they do not represent a completely true picture of the cost savings realized. If we re-configure the data to reflect net present value (NPV) of the original expenditure vs. future value of dollars saved, additional economic justification becomes apparent. Briefly, the value of ***not working over*** a well due to a corrosion failure increases with the time value of money. More specifically, these values are illustrated in the following charts. Figure **3** represents undiscounted capital expenditure over an assumed twenty year well life burdened with the previously-determined seven-year IPC life cycle.

Conclusions

Historically, the construction of a barrier between a corrosive fluid and a given material has been the most effective means of protecting a valuable asset from oftentimes unnecessary destruction. The evolution of the lining process for tubular goods has culminated in the prolific advance of composite materials as corrosion barriers, especially in the oilfield environment. Costly corrosion damage has been largely mitigated by protecting the tubular goods with Glass Reinforced Epoxy liners, a material that has proven to be highly resistant to many forms of corrosive environments, highly effective in gas service and well-suited to both downhole and surface environments in terms of material strength and performance.

GRE is a premium lining product and the initial capital outlay for GRE lining exceeds that of internal plastic coating (IPC) and thermoplastic lining products such as PVC and HDPE. However, the performance of GRE and the longevity of projects using GRE lined tubular products in service are well-documented. The economic advantages of an incremental increase in expenditure at the outset of a project are made apparent upon examination of the costs of using less expensive products which will ultimately require high operating expense over the project life.

References/Acknowledgments

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(Undiscounted Dollars)	$1.00 x 1,000,000
Cost of Workover- IPC	$3.10
Annual Cost of Workover	$0.44
Cost of Workover- GRE	$3.42
Annual Cost of Workover	$0.49
Additional Product Life to Payout (years)	0.74 yr.
Additional Product Life to Payout (months)	8.89mo.

Figure 1

	US Dollars Undiscounted
Coating Cost	$17,500.00
Annual Cost of Coating	$2,500.00
GRE Lining Cost	$21,100.00
Annual Cost of Lining	$3,014.29
Additional Product Life *to* Payout (years)	1.44 yr.
Additional Product Life to Payout (months)	17.28 mo.

Figure **2**

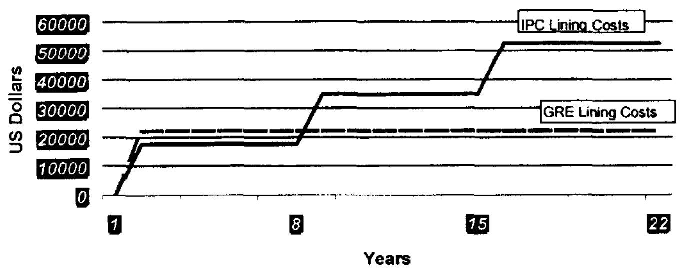

Figure 3 - IPC vs. GRE Lining