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GRE Composite-Lined Tubular Products in Corrosive Service: A Study in Workover Economics

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Abstract

This paper is a two-part discussion describing Glass Reinforced Epoxy composite linings manufactured and installed in oilfield tubular goods where the material functions as a barrier to corrosion. The paper first focuses on GRE composites in terms of effectiveness and product life compared with less-costly corrosion solutions (such as internal plastic coatings (IPC) and thermoplastic materials like HDPE and PVC). Next, actual case history economic data is presented to qualify the use of Glass Reinforced Epoxy-lined tubular goods over IPC for corrosive seawater injection service in the North Sea. These data are then extrapolated to construct a similar economic model based on workover costs in the Permian basin of West Texas. Additionally, net present value (NPV) analysis can be used to illustrate the saving s in long term operating costs over the life of the project.

Introduction

Though used extensively worldwide, GRE composite-lined tubular goods have demonstrated an especially wide acceptance in the Permian Basin of West Texas and eastern New Mexico as injection tubing for secondary and tertiary recovery of oil where injected formation water and CO_2 combine to form some of the world's most corrosive downhole environments. This acceptance is a direct function of the material's durability and long product life. Although GRE-lined tubular goods are most commonly used in corrosive service where the downhole temperature is below 300° Fahrenheit, novel manufacturing techniques have enabled tolerance of higher temperatures and generally harsher environments. This ultimately provides the end user a lower cost alternative to expensive steel alloys and opens up new opportunities in corrosive gas production and gas-lifted oil production where previously chromium-nickel alloys have been the exclusive choices. The new generation of GRE-lined tubular products can now be reasonably utilized in deep gas production and corrosive high-temperature injection on land and in offshore environments.

A major North Sea operator qualified GRE linings over internal plastic coating for seawater injection. This qualification was premised on favorable workover economics made possible by the increased product life of GRE as opposed to that of IPC. Use of GRE-lined injection tubing resulted in substantial savings of funds that would have been spent for high-cost workovers and material replacement costs. When Net Present Value (NPV) of these savings are compared to the higher capital expense to specify the premium material (vs. selection of the less durable, lower costing material) the fundamentals of this model are born out in all environments.

The Cost of Corrosion

The impact of corrosion throughout nearly every industry in business today is devastating. NACE estimates that $300 Billion per year is subtracted from U.S. industrial operations alone. About $150 Billion of these costs can be prevented by various forms of corrosion engineering and project planning (1). It is estimated that tubular corrosion by itself costs the oil and gas industry billions of dollars per year.

Kermani and Harrop define the cost of corrosion to the oil and gas industry in terms of capital expenditure and operating expenditure and also point out the costs to HSE (Health, Safety and Environment) relative to oilfield corrosion (2). Four cost categories are identified as follows:

1. The *cost of designing corrosion control into the project (Capex)*. For example, costs in this category are incurred where specialty metals and materials are purchased to avoid corrosion. The premium paid for GRE lining would fall into this category.
2. The *cost of maintaining and repairing corrosion-damaged equipment (Opex)*. The recurring costs of chemical maintenance or the occasional workover unit operation costs are examples of operating expense incurred due to corrosion.

3. The *cost of replacing failed equipment (Opex)*. For example, replacing a string of tubing which failed as a consequence of corrosion fits into this category.
4. The *consequences of lost revenue due to failed equipment*. These are typically cash flow issues where for example, oil production is shut in or injection is ceased to work over a well. Deferred cash flow due to corrosion damage costs the operator lost revenue by postponing total net return from invested funds.

Without question, these figures impact negatively 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 of corrosion, 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.

Preventing damage from corrosion can be achieved by thoughtful implementation of:

- Alteration of Environment
- Material Selection
- Chemical Treatment
- Construction of Corrosion Barrier

The corrosion barrier is the simplest and arguably the most effective process of these alternatives, especially in downhole applications. Composite technology has evolved to the point of feasibly providing economically viable solutions to corrosion in the form of a barrier between corrosive fluids or gases and the steel in service.

Definition of Composites and Lined Tubulars

Composites are defined as fiber-reinforced thermosetting or thermoplastic matrix materials. 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 liners for installation into tubing). Lined tubulars consist mainly of steel tubing with standard oilfield connections lined with composites like GRE or thermoplastic matrix materials such as High Density Polyethylene (HDPE) and Polyvinyl Chloride (PVC) (3).

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. Lined tubulars consist of a variety of downhole and surface tubular goods lined with one of the aforementioned materials (also including cement linings which are outside the scope of this discussion). 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 advanced 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 in gaseous environments has been a strong economic driver for the manufacture and installation of GRE in lined steel tubular goods. For example, the permeability to small gas molecules combined with the low hoop strength of thermoplastics creates a tendency towards liner collapse in CO_2 injection service and gas-lifted production. Temperatures in excess of 150° F are typically outside the capabilities of Polyethylene and Vinyl Chloride thermoplastic materials.

GRE liners also enjoy an advantage as a superior corrosion barrier over less-costly ID coatings. Lining of tubular goods has proven to be a preferred solution to ID coatings with 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 is difficult to achieve. Subsequent handling damage to the coated steel product is also frequently a cause of tubing 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. In addition, the durability of GRE composite yields a higher abrasion resistance for instance, from multiple wireline tool runs and coiled tubing intervention. The GRE lined tubing is capable of providing trouble-free service in high-temperature, gas-saturated corrosive environments where thermoplastic linings and internal plastic coatings oftentimes fail.

Manufacturing of GRE Liners. 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 machining 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 control 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 (T_g).

- Resin content is verified by weight and percentage using carefully defined procedures.
- Samples are cut and measured for verification of 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 an elastomeric compression ring into the coupled area, which upon makeup of the connection, is compressed between the pin ends to isolate the unprotected dimension of the coupling from the injected or produced corrosive gas or fluid. This completes the integrity inside the tubing string and eliminates contact of the carbon steel with the fluid or gas in transport (see Figure 1). The design for this component has proven effective in this application for over 45 years and continues to perform well in a variety of circumstances (4).

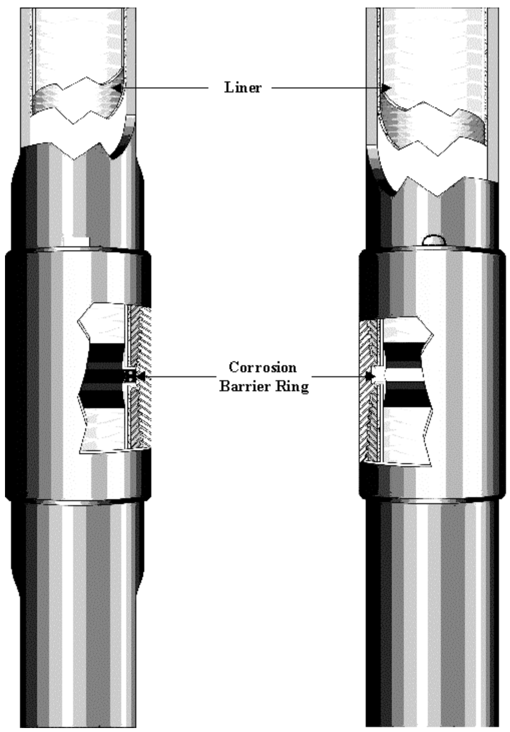

Figure 1

The Need for Protection against Corrosion. Many oilfield processes are detrimentally affected by corrosion. Within the scope of this presentation, four distinct applications are illustrated whereby corrosive fluids or gases are injected or produced through oilfield tubular products.

1. Injection of produced water into reservoir rock to provide enhanced recovery of hydrocarbons often subjects the completion string to harsh corrosive environments. Water flood operations and tertiary recovery involving CO_2 alternating with water (W-A-G injection) provide perhaps the most detrimental of all downhole environments.
2. Disposal well tubulars are commonly adversely impacted by downhole corrosion, especially where corrosive gases (acid gas injection) are combined with produced fluids.
3. Sour gas & gas-lifted production is highly detrimental to carbon steel tubular goods.
4. 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 quite often involved in waterflood 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 sweep the unproduced hydrocarbons from the formation and to maintain reservoir pressure. This fluid is quite often high in salt content and contains varying quantities of dissolved solids. The reaction of carbon steel to high-saline solutions 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 corrosive of all downhole environments. The procedure used in maturing CO_2 floods is to alternate produced water with CO_2 injection (Water-Alternating-Gas or 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 with carbon steel. Well service costs and HSE issues will manifest themselves over a very short period of time and operating costs will quickly rise. The performance of GRE as a corrosion barrier in this environment is unmatched, due largely to the material's durability and compatibility with CO_2 and corrosive fluids in general.

Another benefit of GRE composites presents itself in CO_2 injection at the molecular level. The CO_2 molecule is very small and has the ability to penetrate most thermoplastic materials used at one time almost exclusively as tubular lining products (a notable exception is the use of cement for lining tubular goods). PolyVinylChloride (PVC) and High Density PolyEthylene (HDPE) are examples of liner 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 corrosive gas or fluid to the steel will result in a material failure and the costs associated with lining the tubing will not contribute to the life of the project.

Oswald (1987) presents the results of testing done on GRE liners grouted into steel tubing with an intentionally bored and tapped "leak" through the wall of the tubing and into the grout. A gauge was installed in the tubing to measure pressure. With CO_2 compressed in the liner at 300 psi over an 815-day period no pressure readings over 0.5 psi were recorded. This indicates the GRE's impermeability to the CO_2 molecule relative to other tested materials such as HDPE where the permeability measured was over one million times greater than that of GRE (5).

GRE is an amorphous fiber-reinforced solid with a unique high hoop strength and superior resistance to gas penetration. The nature of the GRE composite is such that the cross-linked molecular structure of the cured epoxy inhibits the passage of gas through the liner, thereby reducing the detrimental effects of corrosion due to surface exposure. Additionally, the strength of the material mitigates the possibility of subsequent liner damage upon rapid depressurization of the tubing string. The orientation of the glass fibers increases hoop stiffness which gives the liner increased ability to resist blistering and collapse.

Disposal of Corrosive Fluids and Gases. Produced disposal fluid 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. A major operator in the western Permian basin of New Mexico is disposing of gas with 50% CO_2 and 50% H_2S and in excess of 4400 bbls. water per day. Another major operator in central Michigan is injecting a mixture of 65% H_2S and 35% CO_2 with about 1000 bbls. of water per day.

GRE composite material in service as a barrier to corrosion damage caused by acid-forming gas components is not unique to the oilfield. Industrial waste gas (gaseous sulfuric acid, e.g.) 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 (6).

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 (7). Additionally, GRE lined steel tubing in production wells have been demonstrated to retard the tubular deposition of paraffin and asphaltenes.

To qualify solutions to tubular corrosion in sweet production Lewis and Barbin (1999) have presented advantages and disadvantages to various internal coatings tested for resistance to acid intervention, wireline abrasion and impact resistance. Also tested were the ability of the coatings to perform under high temperature (to 300° F) and high CO_2 gas concentration (autoclave and rocker arm tests). Lewis and Barbin concluded that "all coatings did not perform equally well in each test. Most of the coatings had strengths under some test conditions while exhibiting weakness in other test environments". A nylon-based coating for example, performed very well in the wireline abrasion resistance trial but disbonded in acid. In the impact resistance test, the nylon coating "flowed", resulting in exposed steel. Modified epoxy-phenolic coatings were able to tolerate higher gas concentrations under more severe temperatures but could not withstand exposure to acid. This coating was also compromised during the wireline abrasion test (8).

Where internal plastic coatings did not perform uniformly under the variety of exposures and procedures administered by Lewis, et.al., a stark contrast exists for GRE lining materials. Notably relevant to this series of tests is the documented ability of GRE to withstand well intervention with acid (15% and 28% HCl, e.g.), wireline abrasion (GRE has been tested extensively for wireline abrasion resistance to qualify for large diameter injection by a major North Sea operator) and nominal impact encountered in routine intervention. Additionally, GRE liners have demonstrated exceptional capabilities in temperatures exceeding 300° F in the presence of H_2S and high concentrations of CO_2 gas mixtures. GRE gives the operator flexibility beyond what is offered by selection of the various plastic coatings described in the Lewis and Barbin procedure.

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 GRE composite permits the liner to withstand 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, flanged and welded connections.

The aforementioned high costs of corrosion with respect to HSE periodically become apparent when material failure in a surface line bearing corrosive fluids or gases is identified as the cause of an environmental catastrophe. The cost of compliance with environmental regulations has been extremely high in the history of oil and gas production. The damage from a leaking surface line is always publicly 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 forward-looking increased CAPEX dollars at the commencement of a project in exchange for lower operating 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. These operating costs are defrayed when project life is expected to surpass the useful life of a lined or coated product. The following model illustrates actual research performed by a North Sea operator to qualify GRE lined tubulars for water injection service to increase design life from present limits of five to seven years to beyond twenty 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. The cost of the workover includes rig time, the tubing string, completion fluids and accessories. This cost is expected to increase by the amount of \$330K to employ GRE lined tubulars (allowing also for much higher-cost 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 =\$0.447M/year….(1)

Using GRE lined completions, the cost of working over a well is \$3.46M. *The completion only has to have an additional life of nine months beyond IPC life to pay out the incremental premium of the GRE lining.* The marginal cost of the GRE lining is calculated in equations (2). To calculate the time for payout, the marginal cost is divided by the annual cost of the IPC workover previously determined in equation (1) (see Table 1).

\$3.46M - \$3.13M = \$0.33M…………………….(2)

\$0.33M ÷ \$0.447M/year = 0.74 years or about nine months …………………………………………….(3)

North Sea Coating/Lining Costs (USD Non-Discounted)	
Cost of Workover- IPC	\$3.10M
Annual Cost of Workover	\$0.44M
Cost of Workover GRE	\$3.42M
Annual Cost of Workover	\$0.49M
Additional Product Life to Payout (Years)	0.74
Additional Product Life to Payout (Months)	8.89

Table 1

Land-based operations involve considerably lower costs but the relative economics are based on the same model. To form a more concise basis for comparison, all costs other than the coating and lining expenses are stripped away. To extrapolate the previous example, internally coating a string of tubing for a West Texas injection well (10,000', for example) now costs approximately \$17,500. The cost of an average workover in the Permian Basin is very generously estimated at between \$2500 and \$3000. The incremental cost of lining API tubing with GRE composite material as opposed to coating with plastic is approximated at 20%. For a 10,000' string of 2 3/8 API 8rd tubing, this is an average cost increase of \$3600. The GRE lining now costs \$21,100. Again, using an estimation of a seven-year maximum product life for IPC tubing, calculate the annual lining cost of the IPC tubing:

\$17500 ÷ 7 years product life = \$2500…………..(4)

If the incremental cost of the GRE tubing = \$3600, the economics of this situation indicate that the GRE will pay out after an additional 1.44 years or approximately 17 months of service (see Table 2):

\$21,100 – \$17500 = \$3600……………………….(5)

\$3600 ÷ \$2500/year = 1.44 years or about seventeen months…………………………………………………..(6)

West Texas Coating/Lining Costs (USD Non-Discounted)	
Cost of Workover- IPC	$17,500
Annual Cost of Workover	$ 2,500
Cost of Workover GRE	$21,100
Annual Cost of Workover	$ 3,014
Additional Product Life to Payout (Years)	1.44
Additional Product Life to Payout (Months)	17.28

Table 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, with multiple installations lasting beyond 20 to 25 years.

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. NPV of future 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 2 represents undiscounted capital expenditure over an assumed twenty year well life burdened with an IPC life cycle of eight years.

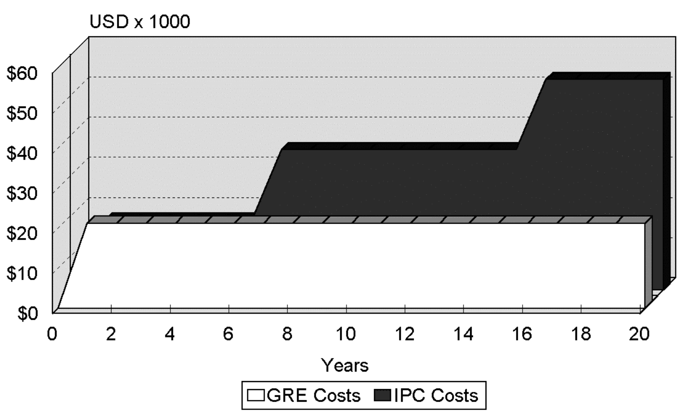

Figure 2

Estimating procedures used during the preparation of a capital budget often involve making assumptions based on both historical data and previous experience To restate the costs of corrosion in terms of lost return on investment (ROI) can also be wildly subjective due to the assumptions one must make. But these costs and the impact of corrosion on an operator's finances cannot be ignored. To reiterate Kermani et al.'s four previously identified costs and to illustrate the financial aspects of budgetary considerations based on value, the following example is presented. In this exercise, the operator is making the decision to purchase either a premium GRE lined W-A-G injection tubing string or a less-expensive internally coated string.

Assumptions:

- The average price of oil equals $20.00 per barrel over the life of the well.
- A plan of depletion (POD) period of twenty years (this is typical for a W-A-G injection installation).
- Loss of production during shut in and workover of this well is 150 barrels of oil per day.
- The cost of a workover procedure (rig costs and assorted services) is conservatively estimated to be $2500 per operation.
- The life of the internal coating is reported by the coating vendor to be eight years.
- The operator's asset manager expects an eight percent annual rate of return on this asset

Impact of the Costs of Corrosion: Net Present Value of Savings Realized with a Premium Lining

1. *CAPEX* required to design out the effects of corrosion. Our model uses an incremental cost of $21,100 for the GRE-lined tubing versus $17,500 for internal coating. Each is a capital expense but the "premium" for the GRE is valued at $3600:

   $21,100 - $17,500 = $3600………………………......(7)

   To demonstrate the investment value of the GRE lining, it is appropriate to use $21,100 as an initial capital expense.

2. *OPEX* required to service the well and replace the failed tubing (with product life of eight years) twice over the life of the well. Using a conservative $5000 per workover (vs. $2500 in previous model), OPEX includes workover and associated service costs of $10000:

   2 operations x $5000/operation = $10000…………(8)

3. *Replacement Costs* for failed tubing string. Since the cost of steel tubing is not a factor in this exercise, it is appropriate to examine only the costs associated with putting the existing tubing back into service. Assuming that the integrity of the used tubing is not compromised over the life of the coating, the cost of re-coating two strings of internally coated tubing is $35,000:

   Re-coat two strings x $17,500 each = $35,000……(9)

4. *Cost of lost production* due to ceased injection. At our assumed 150 barrel per day lost production factor, this cost over twenty years is very conservatively estimated to equal $6000 over the POD period:

150 barrels x $20/barrel = $3000…….. …………....(10)

2 operations x $3000 = $6000..... ……….………(11)

This is sometimes treated as deferred cash flow. However in this model, it is discussed in terms of actual lost revenue.

Tables 3 and 4 illustrate projected costs and a simulated capital budget where it can be demonstrated that, over the life of the well, there is a strong case for the premium lining product. The Net Present Value (NPV) of the cost savings over the life of the well has only to exceed the original capital outlay (break-even point) in order to bear out the economic viability. Costs have been annualized in this example by dividing each individual cost by the product life of eight years.

Year	Marginal Cost of New GRE Lining	Cost to Replace Coating	Cost of Workover	Cost of Lost Production
0	$3,600	$0	$0	$0
8	-	17,500	5,000	3000
17	-	17,500	5,000	3000
Totals	**$3,600**	**$35,000**	**$10,000**	**$6000**

Table 3

Capital Budget Simulation	
GRE Product Life Years	20+
IPC Product Life Years	8
Workovers per Year	0.125
Recoating Costs- Life of Project	$35000
Lost Production Costs- Life of Project	6000
Workover Costs-Life of Project	10000
Total Costs	**$51000**
Annualized Coating Costs	$4375
Annualized Lost Production Costs	750
Annualized Workover Costs	1250
Total Annualized Costs	**$6375**

Table 4

In this case the Present Value (PV) of the cost savings (money *not* spent working over the well) equals $59000 based on the expectation of an 8.00 percent return. It is determined that the multiplier (P_n) representing the present value of an annual payment of $1.00 invested at rate (r) of 8.00% over a twenty year period of time (n) equals 9.82:

$$P_{n=1-20\ years} = \frac{1}{r} \times \left[1 - \frac{1}{(1+r)^n}\right] = 9.82 \ldots\ldots\ldots(12)$$

The following calculation illustrates calculation of NPV of the savings over the twenty-year POD:

$6375 x 9.82 = $62600 ……………………….…....(13)

$62600 PV - $3,600 CAPEX = $59000 NPV........(14)

The marginal cost of the asset (the GRE lining) equals $3600 (note that this is a CAPEX item). The difference is $59000 which is well over the break-even point. This makes a strong case for increase in capital expenditure up front as opposed to increased operating and replacement costs and the cost of lost production over the life of the project.

This is an obviously oversimplified illustration of cash flows out of the project. A more realistic model is based on accounting for total cash inflows and outflows; therefore a revenue stream must be included in the model. A conservative assumption would be to stipulate that the impact of the injection well adds $10000/year to the project after subtracting Lease Operating Expense (LOE).

Table 5 illustrates that the initial investment of $21100 represents the only negative cash flow out of the project when GRE is specified. In **Table 6**, an initial investment of $17500 (purchase price) plus additional cash flows to work over the well and recoat the tubing at years eight and sixteen are required for the project when IPC is selected. The following tables present data acquired using the Total Cost method of Net Present Value accounting for capital budget determination.

Transaction	Yr	Cash Inflow or (Outflow)	PV Factor 8.0 %	PV Cash Flows	Cum PV of Cash Flows
Purchase Liner	0	($21,100)	1.00	($21,100)	-$21,100
Workover/Lost Production Costs	8	0	0.540	0	-$21,100
Recoating Costs	8	0	0.540	0	-$21,100
Workover/Lost Production Costs	16	0	0.292	0	-$21,100
Recoating Costs	16	0	0.292	0	-$21,100
Annual Operating Revenue Net of LOE	1-20	10,000	9.820	98,200	$77,100

Table 5

Transaction	Yr	Cash Inflow or (Outflow)	PV Factor 8.0%	PV Cash Flows	Cum PV of Cash Flows
Purchase IPC	0	($17,500)	1.000	($17,500)	-$17,500
Workover/Lost Production Costs	8	(8,000)	0.540	(4,320)	-21,820
Recoating Costs	8	(17,500)	0.540	(9,450)	-31,270
Workover/Lost Production Costs	16	(8,000)	0.292	(2,336)	-33,606
Recoating Costs	16	(17,500)	0.292	(5,110)	-38,716
Annual Operating Revenue Net of LOE	1-20	10,000	9.820	98,200	$59,484

Table 6

The difference between the NPV of total revenue for each product equals $17,616 in favor of the purchase of the GRE liner. Again it is demonstrated that a small marginal addition to capital expenditure at the beginning of the project yields positive investment gains. This only becomes more apparent over a multiple well project.

The preceding tables are derived by multiplying assumed cash flows by present value (PV) multipliers. The following sets of equations are presented to illustrate the steps taken to derive the figures included in these two tables.

Net Present Value of recoating the string of tubing over the life of the project is calculated by multiplying the costs of recoating by respective PV multipliers for years eight and sixteen. The future value (F_n) equals 1.00 and indicates the value of an annual payment at year number one.

At $F_n = 1.000$ and for $r = 8.0\%$ expected return:

$$PV_{n=8\ years} = \frac{F_n}{(1+r)^n} = 0.540 \ldots\ldots\ldots\ldots (15)$$

$$\$17500 \times 0.540 = \$9450 \ldots\ldots\ldots\ldots (16)$$

$$PV_{n=16\ years} = \frac{F_n}{(1+r)^n} = 0.292 \ldots\ldots\ldots\ldots (17)$$

$$\$17500 \times 0.292 = \$5110 \ldots\ldots\ldots\ldots (18)$$

Total NPV of the recoating investment equals $14560.

Combined workover costs and lost production equals $8000 at years eight and sixteen. In terms of present value these are $4320 and $2336 as follows:

$$\$8000 \times 0.540 = \$4320 \ldots\ldots\ldots\ldots (19)$$

$$\$8000 \times 0.292 = \$2336 \ldots\ldots\ldots\ldots (20)$$

Total NPV of the workover and lost production equals $6656.

Total negative cash flow for the project under these conditions equals $38716 (including the original expenditure of $17500):

$$\$17500 + \$14560 + \$6656 = \$38716 \ldots\ldots\ldots\ldots (21)$$

Without regard to salvage value of the tubing and assuming that the actual impact of the well is increased net revenue of $10000/year, the present value of net annual cash inflows over twenty years equals $98200 as described in the following calculation:

$$\$10000 \times 9.82 = \$98200 \ldots\ldots\ldots\ldots (22)$$

A higher NPV is realized in this example since net present value in favor of GRE equals increased cash flow as a result of decreased negative cash flows from workover and product replacement. Equations 23 and 24 illustrate the net present values of the GRE and IPC investment respectively over twenty years at an 8.00 percent expected return. Equation 25 clearly shows the difference in net present value of the revenue for these two cases in the amount of $17616.

$$\$98200 - 21100 = \$77100 \ldots\ldots\ldots\ldots (23)$$

$$\$98200 - 38716 = \$59484 \ldots\ldots\ldots\ldots (24)$$

$$\$77100 - 59484 = \$17616 \ldots\ldots\ldots\ldots (25)$$

.

With a revenue stream included in the budgeting equations, the benefit of a premium lining is no less than the substantial increase in cash flow expressed here in net present value.

Limitations. The above models are simplified examples and are admittedly insulated from various realities, but to some extent these exceptions can be readily addressed. For instance, some operators would postulate that workover costs are inevitable as a result of any failed component. They may claim that if a failure other than the tubing string occurs (packer failure, casing leak, e.g.), operating costs are unavoidable and tubular goods will be replaced whenever the opportunity presents itself. Additionally, the model is subject to criticism for not presenting alternative budgeting techniques which may yield different results. Finally it can be argued that the useful lives of the various illustrated products are subjective at best and that each product will be in service for a period which will be determined by a number of factors including environment, installation and handling and intervention history, to name a few. Consider the following commentary in response to these claims.

The product life of IPC has been generally represented as eight years in this example based on information published in marketing literature by the coating vendors. The useful life for any coating or lining will likely never be specifically defined due to the wide variety of downhole environments and other factors which make this specification impractical at best. Eight years is therefore an acceptable useful life estimation for this product. Alternatively, GRE installations with well-documented lengths of useful life in excess of twenty years are numerous for this application.

The method used to illustrate the budgeting process is the *Total Cost* approach. This method is easily the most flexible and probably the most widely used method of making a net present value analysis of competing projects. This is due to the fact that the total cost approach accounts for *all* cash flows associated with the project, not just those that are relevant (hence the name "Total Cost" approach). Other methods will yield different results but there is nothing that will disqualify spending a premium for GRE lining as a solution to high operating costs over the life of a project (9).

To address the claim that workover costs are inevitable, it is given that the cost of working over a well will burden the operator regardless of the cause. For example, a packer failure results in workover costs similar to those encountered when replacing a failed tubing string. However, it remains an extremely sensible decision to build quality into the project where the marginal costs are so low in comparison to the benefits. The packer in this example will obviously fail regardless of which lining or coating is selected; additional workover costs will be incurred when the tubing fails. The possibility of this event should not preclude the operator from specifying premium materials where they will ultimately lead to long-term savings.

Conclusions

Historically, the construction of a barrier between a corrosive fluid and a given material has been among the most effective means of protecting a valuable asset from 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. This material has proven to be highly resistant to many forms of corrosive environments, durable to the extent of enabling wireline and coiled tubing operations, 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 unarguably 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.

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