THERMOPLASTIC LINERS, PROVEN STATE OF THE ART IN INTERNAL OCTG WEAR AND CORROSION PROTECTION: A COMPILATION OF CASE HISTORIES INCLUDING PUMPING AROUND THE BEND IN HORIZONTAL WELLS

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ABSTRACT

Thermoplastic liners (TPL) are commonly used to protect the ID of a wide range of oilfield tubulars offering the advantages of increased corrosion resistance, wear mitigation, and ease of tubular installation while diminishing pressure drop issues and maximizing fluid throughput capacity especially in high rate wells operating with high velocity fluids. Furthermore, they may offer a competitive advantage over corrosion resistant alloys (CRAs), plastic coatings and thermoset liner products in extending tubular life. This paper compliments two recent papers focusing separately on water injection and disposal along with oil and gas production applications of the same liner products. The versatility of thermoplastic liners to solve corrosion and wear failures originating from many different root causes, while simultaneously minimizing tubular costs and stocking issues will be emphasized. Most impressively, TPL tubing has successively mitigated rod on tubing wear in horizontally drilled wells where the pump is set well past the kickoff point and into the horizontal section of the completion. Often tubing without any TPL fails in these wells in less than three months; yet, tubing with TPL is still in service in these same wells over nine years later.

The most commonly used thermoplastic liners in oil and gas production service are largely extruded from polyolefins for installation in environments up to 99°C (110°F). For more demanding environments, engineering thermoplastics such as PPS are available to handle temperatures as high as 175°C (350°F) and liners made of PEEK are utilized for more extreme production environments up to 260°C (500°F). All of these materials are significantly more flexible and impact resistant compared to traditional thermoset materials historically used to protect downhole tubing meaning that they can be practically applied in harsh field conditions and maintain a protective barrier against the tubing ID even after pulling/rerunning tubing combined with multiple wireline and coiled tubing surveys. The same liners can be used to protect costly downhole components and jewelry such as packers and tubing anchors. Examples of lined tubulars with both API (American Petroleum Institute) and premium tubular connections will be covered.

This paper will present case studies detailing the successful use of thermoplastic lined tubulars including liner products composed of HDPE, a proprietary polyolefin blend, and PPS in over 2,400 wells operating in 29 different fields. All of the lined tubulars in these wells are still in service today and some were installed back in 1996. A review of critical limitations of the liners such as temperature and diameter changes will also be discussed in an effort to avoid the misapplication of thermoplastic liners. Improved tubular service life, economic benefits, and enhanced flow characteristics due to the high quality surface finish of the liners will be detailed in at least twenty specific case histories and fields including both injection and production well environments.

The fundamental technical benefits of various thermoplastic lined tubulars will be covered with an emphasis on the proven extension of tubing service life using thermoplastic liners. One often-overlooked advantage of TPL tubing is that it reduces the friction of sucker rods on the tubing ID. Data from recent testing by ConocoPhillips that quantifies the benefit will be presented. Furthermore, to exhibit the overall economic impact of thermoplastic lined tubulars, a review of field installation and handling procedures will be presented as well.

1. INTRODUCTION

1.1. Types of Polymer Products Used to Protect Downhole Tubulars

1.1.1 Historical Overview

Going back to the middle of the twentieth century, only thermoset plastic products were significantly used to protect the inside diameter (ID) of production well tubing from corrosion. Initially in the 1940's, thermoset internal coatings with a phenolic primer were applied to the tubing ID to try and isolate carbon steel API oil country tubular goods (OCTG) from attack in the well operating environment. It was found that when they remained intact, these coatings were an effective barrier that mitigated corrosion due to bacteria, chlorides, galvanic attack, and dissolved gases such as oxygen, carbon dioxide, and hydrogen sulfide. These coatings were thin with minimal resistance to impact and not very flexible, commonly resulting in a breached barrier and unprotected areas of the tubing from handling and in-service induced mechanical damage culminating in tubing leaks. Approximately 20 years later, in the 1960's, thermoset glass reinforced epoxy (GRE) liners were introduced with improved damage resistance compared to thermoset coatings. The most recent developments include a family of thermoplastic liners (TPL) that vary in chemical resistance but the primary distinguishing feature is the allowable service temperature of each polymeric material. With a large focus by the polymer research community in the plastics industry on thermoplastic chemistry, it can be argued that the next generation of tougher tubular protection products will also be thermoplastic materials.

2. THERMOPLASTIC LINER SPECIFICATIONS

2.1 Technical Data on Thermoplastic Lined OCTG

2.1.1 Types and Temperature Limits of Thermoplastic Liners

Western Falcon Polycore™ high-density polyethylene (HDPE) thermoplastic liners have been successfully used for over twenty years to protect downhole tubulars. Although they have performed with a near flawless track record in both new and used tubing in over 30,000 wells, HDPE liners are limited to a maximum temperature of 71°C (160°F) in production well service. Because of that limitation, a new proprietary blend of polyolefins (does not contain any HDPE), known as Western Falcon Enertube™ was tested and developed approximately ten years ago with the capability of operating in temperatures as high as 99°C (210°F). The unique blended polyolefin liner has now been used successfully for over nine years in downhole production tubing. As deeper corrosive production wells were considered, Western Falcon Ultratube™ liner made from polyphenylene sulfide (PPS) was developed over eight years ago with the capability of operating in wells with operating temperatures as high as 175°C (350°F). Finally, the most recently developed thermoplastic liner product is Western Falcon Extremetube™ manufactured from polyetheretherketone (PEEK) polymer designed to handle corrosive environments downhole as hot as 260°C (500°F). While Western Falcon Extremetube™ is worth mentioning for high temperature severe service environments, the PEEK liner product is new and not covered in the context of this paper. The higher temperature engineering thermoplastic liners are significantly higher in cost compared to the lower temperature polyolefin liners.

Temperature is just one important variable that must be considered when evaluating any polymer for use downhole and TPLs are no exception. It is important to accurately assess the entire environment that the liner will be exposed to both operationally and during well servicing and treatments. At a minimum, the maximum pressure, maximum temperature, gas composition, liquid hydrocarbon composition, aqueous phase composition, and relative production rates for all produced fluids must be reviewed to properly select a liner material that will offer acceptable service life limits in each well. A complete holistic evaluation of the well environment is warranted before deploying any polymers into the well as some of the liquids or gases in the wellbore may actually reduce the allowable operating temperature and pressure for a liner.

2.1.2 Properties, Dimensions, and Installation of Thermoplastic Lining Systems

Thermoplastics are typically much more ductile and resilient compared to their thermoset counterparts used to protect downhole tubulars. The increased ductility translates into a material that is very resistant to damage from wear (abrasion from sand, wirelines, both rotating and reciprocating sucker rods and coiled tubing), impact (sucker rods, connection stabbing and makeup, and wireline tools) and flexing or yielding (common on the thin pin ends of connection systems of OCTG) of the steel tubing substrate they protect. Primarily because of the unique combination of wear resistance and flexibility, the primary use for TPL tubing today is to stop rod on tubing wear downhole especially in corrosive environments where the synergistic combination of corrosion and wear result in very short well run times. Use of today's TPL OCTG has drastically extended the life of tubulars by minimizing the effect of in-service induced damage to the polymeric protection barrier compared to other materials. Additionally, thermoplastic materials are elastic and carry a dimensional memory (meaning they tend to stretch but then return to their original configuration and dimensions). For this reason, thermoplastic liners are manufactured larger in outside diameter (OD) than the ID of the steel tubulars they are inserted into which allows for the formation of a "tight fit" mechanical bond compressing the OD of the liner tightly against the ID of the steel OCTG. Unlike other tubular protection products, the lack of any adhesive or chemical bond to the steel allows the liner to move independently from the steel and maintain its ductility and elongation properties (as opposed to becoming limited by the ductility of the steel if the two were bonded where the polymer barrier-OCTG bond, the liner material, or both are compromised). Western Falcon has developed a proprietary method to form a large "flange" on each end of the tube composed from the original liner material (excess that is left extending beyond the ends of the tubular when it is lined). This proprietary procedure creates a continuous seamless thermoplastic tube without any leak paths at the liner connections (i.e. the liner and end flanges are continuous and from the same original extruded thermoplastic tube). An example of this "flange" or anchor is shown in Figure 2. The liners range in thickness from approximately 3 to 10 mm (0.120 to 0.400 inch) depending on the diameter of pipe that is lined. A wide range of OCTG diameters have been successfully lined ranging from tubing as small as 1.900-inch OD to casing as large as 7-inch OD. In order to provide a protective polymer layer thick enough to withstand most common OCTG handling practices, the liners typically reduce the tubular bore by between 6 mm and 20 mm (0.240 to 0.800 inch) on tubulars in this size range (see Table 1). A new lining machine has been engineered by Western Falcon to line tubulars as large as 16-inch OD with the same thermoplastic liner products.

2.1.3 Surface Finish of TPL Products and Effects on Pressure Drop

As previously noted, the presence of a TPL robust enough to withstand common oilfield handling creates an undesirable ID constriction in downhole tubulars. Because of the obvious diameter reduction, it is common to imply that the mass transfer capacity of the tubular is reduced and/or the pressure drop to move the same amount of fluids will increase. Historical fluid dynamics research by Osborne Reynolds (prominent Anglo-Irish innovator) in the 1880's proved that this is not always the case. Reynolds concluded in his research that the surface roughness of a pipe is one of the five primary variables that determine the capacity and pressure drop of fluid flow in a pipe. He discovered that this influence is greater at higher velocities and in turbulent flow regimes.

Measurements using a surface profilometer prove that TPL tubulars are approximately 30 times smoother than new (at the mill prior to installation in service conditions) bare carbon steel OCTG: 1.5×10^{-3} mm for the TPL ID surface versus 4.6×10^{-2} mm R_{ZDIN} values for the ID of new steel OCTG. This difference can be significant. When modeling the flow regimes for producing wells, the surface roughness alone (even when also taking into account the smaller ID caused by the TPL) can produce a decrease in the friction component of the pressure drop of over 35 percent (this example assumes high flow rates in tubing restricted conditions). This is just one example showing high rate increases simply by utilizing a theoretically smooth pipe ID surface in a turbulent flow regime. By placing the correct values for surface roughness and nominal ID in modern nodal analysis programs that incorporate accepted fluid flow models using the appropriate flow regimes in pipe, each individual case can be analyzed to verify if a benefit is present and predict the expected magnitude of that benefit. It is important to note that bare steel surfaces will typically corrode or form a passive film on the ID that will cause the surface to become rougher once they are run downhole. However, a properly selected TPL is inert to the operating environment and should maintain the smooth surface while in operation. Because of this deterioration of the steel surface, the pressure drop in many bare steel production (or injection) wells can actually increase over short time intervals without any other changes in flow conditions.

2.1.4 Compatibility of TPL with OCTG Connections

Many different types of tubular connection systems (thread system designs) are used with TPL products. Both API (see Figure 2) and premium specialty threaded and coupled products can be successfully lined using TPL systems. In the past, premium threads have incorporated a corrosion barrier ring to act as a transition between the metal sealing surfaces and the polymer protection system used on the ID of the tubing. One advantage of TPL tubing is that the liner already has a prefabricated substitute for the corrosion barrier ring on the end of the tubing with the “flange” anchor on both ends of the liner extending past the end of the threaded tubular. In many cases, it is possible to modify existing “approved” tubular connection systems to accommodate the TPL system. Western Falcon is currently working with connection manufacturers to finalize “TPL” versions of their connections for various operators. One particular example of this is shown in Figure 1. It is important to note that desirable connection design characteristics such as a flush ID, torque shoulders, and sliding (even pin nose) tapered radial seals (both primary and secondary) can be compatible with TPL lined threaded and coupled OCTG. One unique advantage of using TPL lined tubing with premium connections is that the proprietary end “flange” acts as a compressible transition between the metal-to-metal sealing surface and the corrosion barrier liner. When using other liners or coatings in tubing, a separate thermoplastic corrosion barrier ring (that can be inadvertently removed by downhole tools) is required to accomplish this purpose.

2.1.5 Field Handling and Installation Practices

TPL OCTG do not require special equipment to install or remove the string from the well. If API threaded and coupled connections are used, API minimum torque is recommended to extend the life of the threads and ultimately the tubing string without causing drift obstructions. In all cases, the maximum operating temperature for the liner in use must not be exceeded (not even for short periods like hot oiling or hot watering a well). Pin end thread protectors are required when standing strings back (to be installed immediately after breaking connections) on the rig floor and should remain on the tubing until immediately prior to stabbing the connection above the slips on the well servicing unit when running TPL OCTG. Tools with very sharp metal surfaces should NOT be operated inside of TPL OCTG. If there is any concern that the liner may have been compromised from severe mechanical damage (i.e. fishing of parted rods) or the drift ID is similar to tools that will be run in the well, the lined tubing should be drifted when rerunning the string back in the well.

3. COMMON ISSUES IN PRODUCTION WELLS PROMPTING THE USE OF TPL TUBULARS

Oil and gas production wells present several unique problems for nonmetallic materials. The wells often contain multiple phases (aqueous, liquid hydrocarbon, solid and gas) and many different mixtures of corrosive and abrasive materials. These phases can exist in numerous types of flow regimes and often operate under elevated temperature and pressure conditions. Additionally, chemical and mechanical treatments (intrusive well bore work with wirelines and coiled tubing for example) are often performed on wells to remediate surface deposits, stimulate the formation and many other reasons. The TPL must be able to resist chemical and mechanical alteration from all of these common completion and production practices.

Of course, the most common reason for deploying a barrier on the tubing ID is protecting it from corrosion by the production environment. The unique chemically inert properties of the TPL products used in production wells make them a great barrier to corrosion caused by bacteria, carbon dioxide, hydrogen sulfide, salts, oxygen, water, high velocities, galvanic currents, acids, pH fluctuations, etc… Other methods utilized to treat internal production tubing corrosion issues are thermoset coatings, GRE liners, corrosion inhibitors, biocides, oxygen scavengers, etc… When the corrosion issues become very severe under unique conditions, CRA tubulars are required to counter the corrosive environment. However, as producing wells age and reservoir pressures decline; it is common to utilize forms of artificial lift to keep the fields economical to produce. Some of the most common forms of artificial lift such as reciprocating beam pumps, progressive cavity pumps and plunger lift require the movement of another rigid object (sucker rods or a plunger) inside of the production tubing that cause wear. When wear occurs in a corrosive environment or in the presence of abrasive solids (sand or coal fines), it can cause the tubulars to fail in a matter of a few weeks due to rapid removal of the passive film created during the electrochemical corrosion interaction. The most common methods of treating downhole wear issues are sacrificial rod guides, solid control completion methods, rod rotators, and tubing rotators. All of these simply extend the time to failure but do not solve the problem. Over the past sixteen years, TPL tubing has solved many wear and corrosion and/or abrasive aggravated wear tubing problems that were considered otherwise untreatable. For this reason alone, TPL lined tubulars have established a unique new niche to protect tubulars from wear and allow the use of various artificial lift methods in wells that were otherwise not considered candidates for other corrosion control methods for many reasons including excessive wellbore deviation, rod friction or extremely corrosive fluids.

In wells with excessive amounts of CO_2 and/or H_2S at high pressures and temperatures, the use of existing thermoplastic lined tubulars might be precluded due to gas permeation associated issues. A modification of the existing thermoplastic liner products is under development specifically for these extreme environments. That modification includes the use of a special gas diffusion barrier located in the wall of the existing liner products that does not allow the acid gases to permeate to the backside or OD of the liner from the produced gases and fluids. Testing on this modification continues as this paper is written.

4. FRICTION OF SUCKER RODS ON TUBING

It is common practice to use a sucker rod string inside of production tubing to operate a sub-surface pump and move fluids up to the surface. Historically a conventional rod string held together with individual rod lengths (typically 20 to 40 feet in length) connected using male threads on each end and a coupling at each joint have been used; however, more recently continuous coiled rods of solid steel bar have been deployed for this purpose. In both cases, the rods either reciprocate up and down or rotate to operate the pump at the end of the tubing string. This rod movement commonly causes wear of both the rods and the tubing ID surface. The severity of the wear is dependent on several factors including (but not limited to) the side load of the rods on the tubing, the geometry of the wellbore, the size/makeup/geometry of the rods and tubing, the stroke length/frequency or rotational velocity of the rods, the makeup of the produced fluids, and the presence of produced solids in the production string. Nonetheless, the friction of the rods on the tubing is a very important factor required to properly design rod strings in artificially lifted wells. TPL tubing has been successfully used in over 20,000 rod pumped wells to mitigate rod on tubing wear and extend the service life of the well.

Several years ago, a proposal by Mr. John Patterson of ConocoPhillips was introduced to quantitate the difference in friction between bare and TPL tubing. It was hypothesized that the presence of the TPL liner also reduced the friction of the rods on the tubing. If so, in question was if it was enough of a reduction to allow:

- Use of a smaller pumping unit
- Design of a lower strength (more ductile and lower hardness steel with longer fatigue life) rod string
- The ability to use positive displacement rod pumps in deeper wells
- Reduce the loads on the same rod string and increase its fatigue life
- Reduce the power required to produce the well and increase the overall artificial lift efficiency

To answer these questions, ConocoPhillips funded and undertook a study comparing the friction of rod boxes on bare API J-55 tubing to TPL tubing at various side loads (up to 170 lbs.) and temperatures. The results of this study were presented in a paper at the 2010 Southwest Petroleum Short Course by Mr. Mike Berry titled “Sucker Rod Coupling Friction in HDPE Lined Tubing”[2]. It is important to refer to the entire paper to understand the complete context of the study; however, Figure 21 of the paper illustrates that the friction of the rod boxes on the TPL tubing is approximately one-half (at 95°F) to two-thirds (at 170°F) of the friction of the same rod box under identical test conditions. The paper also offers a mathematical relationship for the correlation of the drag ratio of HDPE internally lined to bare steel tubing. It is important to note that the HDPE liner used in the study was a unique formulation currently only available from the supplier involved in the study. The data supports the reduction in peak polished rod loads reported in fields using TPL tubing and validates the ability to rod pump deeper wells when they are completed using TPL OCTG. Many aspects of cost reduction are now being realized by modeling wells using this benefit including reduction of pumping unit sizes in some fields.

5. PUMPING “AROUND THE BEND” – HORIZONTAL COMPLETIONS

Many wells today are drilled with horizontal sections in the wellbore to take advantage of more efficient completion techniques. Usually it is desirable, to increase pump efficiency and production rates, to set the pump in the horizontal section of the completion. In order to accomplish this, the rod string must extend “around the bend” and will point load on the tubing ID below the kickoff point in the wellbore. Due to the high side loads on the tubing, extreme wear commonly causes the tubing to breach very quickly and create communication with the annulus of the well. Several informal studies have taken place to “optimize” the relationship between the efficiency of the artificial lift and the “pump angle” or depth of placement of the pump into the bend below the kickoff point that does not cause the rod on tubing wear issue to be so severe that several costly workovers are required each year to replace holes in the tubing.

TPL tubing has been successfully used for over ten years to mitigate rod on tubing wear in horizontal completions with the pump set <u>well into the horizontal sections of the well</u>. In shallow, lower temperature wells the polyolefin liners have proven to be most cost effective and capable of protecting the tubing from abrasion of the rods (even in the presence of produced formation sand). In a small percentage of cases, with higher side loads and/or temperatures, Falcon Ultratube™ and even Falcon Extremetube™ have been used below the kickoff point to solve the most severe wear problems in the most severe rod wear situations. It is hypothesized that the softer polyolefins are most effective at stopping rod on tubing wear at lower temperatures and side loads but the higher strength and harder engineering thermoplastics have proven to be superior at higher temperatures and side loads where the softer polyolefins are more susceptible to damage. This is an important discovery because in the past we only had polyolefin liners as a TPL option but today more advanced polymers are available to solve these age-old industry rod on tubing wear issues. Perhaps more importantly, the use of TPL tubing allows the use of positive displacement pumps set in the horizontal leg of the well in wells that previously were abandoned or used less efficient and/or more costly forms of artificial lift because of the wellbore geometry (deviated, corkscrewed, dog-legged and now even horizontal).

6. OCTG ECONOMICS

It is common to design OCTG corrosion control systems by looking at the past history of the wells in a field. In fact, it is very common for our industry to employ reactive strategies that minimize capital costs when operating a given field. This process is often driven by potential change in ownership of fields and looking at short term operating economics for each operating profit center or field.

When a company has the unusual luxury of drilling an oilfield and operating it to optimize the long-term economic benefits, a different approach can be taken. One engineer operating in the Permian Basin actually calculates the price per foot (meter) of his tubing on a daily basis taking all of his measurable variables into account. His studies have shown that the versatility of the tubulars and the type of corrosion control methods utilized, together with the quality of steel that is run downhole, all have a large impact on his tubing costs. This operator has been able to purchase large quantities (annual or semi-annual estimated requirements) of specific types of TPL lined tubing, maintain a local inventory, and use the tubing to protect both injection and production wells alike. Most importantly, new wells in this field are completed using the same proven system to avoid the need to purchase a second string of tubing after the first unprotected one fails. This approach has significantly reduced down time in the field which has compounded economic gains due to higher monthly production values, lower lifting costs (fewer workovers and tubing failures), and no need to constantly replace tubing when wells workovers are necessary. This field is now used as an internal engineering economic model for producing corrosive artificially lifted wells in mature oilfields using enhanced recovery methods. It is believed that establishing a standardized method to evaluate the true cost-benefit of each variable used in completing these wells was instrumental in deriving the best formula for engineering an optimal well completion design for this field.

7. TWENTY-NINE DIFFERENT THERMOPLASTIC LINER CASE HISTORIES IN DOWNHOLE WELLS

<u>Past Field Performance in Various Operating Conditions</u>

- <u>Heavy Oil Production, South America</u>

  - One operator in South America has been using lined 4 ½-inch tubing in more than 40 wells to solve rod on tubing wear failures for approximately six years with the first TPL tests run in late 2000. The wells produce a significant amount of formation sand and operate at temperatures below 65°C (150°F) and at depths from 900 m to 1,500 m (2,950 to 4,900 feet). The lined tubing has lasted up to twelve times longer than bare tubing and is still in service today. The water cuts in these wells vary from one percent to seventy percent. These wells are lifted with both beam and PC (progressive cavity) pumps.

- <u>Woodbine Formation, East Texas, USA; Water Disposal Company</u>

- Produced water disposal company has completed approximately 10 wells with 1,100 meters (3,600 feet) of HDPE lined 5 ½-inch casing with a lined drift ID of 4.500-inch in each well. The first wells were installed in January of 2004. The operating pressure is over 100 bars (1,450 psi) and the bottom hole temperature is approximately 50°C (120°F) with injection rates averaging 17,000 BPD per well. The water has a specific gravity of 1.046 and contains 38,000-ppm chlorides. As a produced water disposal company, the operating costs for their water disposal wells are very important. With over 6 ½ years of experience using HDPE lined casing in their wells, they have closely studied the effect of the smooth ID thermoplastic liner on their pressure drop and pump energy costs. They have reported substantial energy savings compared to unlined casing wells high enough to pay for both the TPL and new API 5CT J-55 steel injection casing string in less than 18 months.

  - <u>Artificially Lifted Oil Wells, Alberta, Canada</u>

- An independent operator has operated over 200 internally HDPE lined sour light oil production wells since March of 2007 without any reported problems or leaks in the lined tubing. The wells are completed using TPL 3 ½-inch tubing at a maximum depth of 1,300 meters (4,300 feet). Most of the wells are horizontally drilled completions and about 70 percent of them are completed using PC pumps with the remainder using beam pumps. The TPL has solved issues from holes in the tubing due to deviated profiles, minor scale problems, corrosion, and paraffin deposition issues. Run life for bare tubing has increased from four to six months to over five years (and still going). Prior to running TPL tubing, the pumps were failing in less than one year; now, pumps are lasting between 1 ½ and 2 years on average.

  - <u>Permian Basin, USA; Water Injection</u>

- One independent operator has been using HDPE lined tubing to complete over 60 water injection wells ranging in depth from 1,150 m to 1,300 m (3,800 to 4,300 feet) with temperatures up to 60°C (140°F) and pressures of approximately 69 bars (1,000 psi). These wells are injecting approximately 2,000 BPD of produced water in 1.600-inch ID drift and 2.000-inch ID drift lined tubulars. The first wells were installed in 1998 and they are all still operating today without any reported tubing leaks or failures.

  - <u>Directionally Drilled Wells, Pacific Coast, USA; Sandy Oil Production</u>

- This operator has installed over one million meters (3.28 million feet) of TPL 2 7/8-inch and 3 ½-inch tubing in well over 1,000 beam pump and PC pump wells. A variety of different liner materials have been used including PPS and Falcon Enertube™ but the majority is HDPE. Due to a combination of corrosion, rod on tubing wear, and abrasion from produced solids, many of these wells were failing with bare steel tubing in two to three months. In an effort to save money, this operator has lined a significant amount of their own used steel tubing that was rethreaded and inspected prior to installation of the TPL. In 2002, a test of two wells (failing in less than 100 days) was undertaken using HDPE liner in green band used tubing. After lasting 250 days in the original test wells, the liner was evaluated with downhole calipers and no measurable wear was found. <u>This operator sets the pumps in the horizontal leg of the wells.</u>

  - <u>Velma Field, Ardmore Basin, USA; Water Injection</u>

- Several independent operators have been using internally HDPE lined OCTG in this field since January 2001. One operator has installed 30 wells with 1.600-inch drift ID lined tubing and 20 wells with 2.000-inch drift ID lined tubing at depths over 1,800 meters (5,900 feet) and temperatures up to 70°C (160°F). These wells inject produced water at rates below 1,000 BPD. No tubing leaks or liner problems have been reported.

  - <u>Southern Alberta, Canada; Produced Water Injection</u>

- Three produced water injection wells installed between September, 2005 and June, 2006 using 1,500 to 1,600 meters (4,900 to 5,250 feet) of 2 7/8-inch HDPE TPL OCTG operating between 100 bars (1,450 psi) and 120 bars (1,740 psi) at temperatures below 40°C (105°F).

    - McElroy Field, Permian Basin, USA; Sour Crude Production Wells

- A major operator has compared HDPE lined tubing to rod guides to solve corrosion and rod on tubing wear issues in the McElroy field. These wells produce sour crude with a high water cut at rates between 40 and 500 BFPD (Barrels of Fluid Per Day) from a depth of between 900 m and 1,000 m (2,950 to 3,300 feet). Prior to using TPL tubing, the wells were failing at an average of once every 116 days with rod guides and bare steel tubing. TPL tubing was first deployed in this field back in 1996 and some of those wells are still producing with the same lined tubing today, over fifteen years later. In fact, recently a well was pulled for a pump repair in this field and the same lined tubing was visually inspected and rerun back in the well after over ten years of service. These wells (and those in a nearby field operated by the same company) are producing from the San Andres formation. The operator wrote an SPE paper (SPE 39815) [1] detailing their success using TPL in this field.

    - Permian, Arbuckle, and Fairbanks Formations; Mid-Continent, USA; Salt Water Injection

- Another independent operator has operated over 40 internally HDPE lined produced salt water injection wells since 2002 without any reported problems or leaks in the lined tubing. These wells operate at maximum temperatures of 60°C (140°F) injecting between 700 BPD and 1,000 BPD of water. The wells are completed using TPL 2 3/8-inch and TPL 2 7/8-inch tubing at a maximum depth of 1,400 meters (4,600 feet).

    - Western Canada; High Water Cut Oil Field

- A large Canadian operator has used HDPE lined tubing to solve rod on tubing wear and corrosion issues in over 300 wells in Southern Alberta. The wells are completed using 2 7/8-inch and 3 1/2-inch tubing all lined with HDPE. This field has experienced some unique corrosion issues as it has been on polymer injection since 2003. Some of the wells are completed with PC pumps but most are reciprocating beam pump wells. The wells are from 1,000 m to 1,200 m (3,300 to 4,000 feet) deep and produce medium API oil with high water cuts. Prior to using lined tubing, the tubing was only lasting 3 to 4 months with rod guides. Boron treated steel tubing was tried unsuccessfully in this field prior to using TPL tubulars. The first TPL tubulars were run in October of 2006 and they are now used in all wells operated in the area by this operator.

    - Brown Dolomite Formation, Oklahoma, USA; Salt Water Disposal

- This salt-water disposal company operates a few wells with HDPE lined OCTG injection strings. The injection strings are approximately 1,600 meters (5,250 feet) deep and utilize 5 ½-inch, 15.5 #/ft, API 5CT J-55 casing with a 4.550-inch nominal lined ID. The injection rates vary between 10,000 BPD and 17,000 BPD of produced salt water. The surface pressure on these wells is approximately 69 bars (1,000 psi) and the maximum bottom hole temperature is estimated to be below 70°C (160°F). These wells have been operating since December 2006 without any tubing related issues.

    - Colorado, USA; Production Wells

- A major oil operator in Colorado has utilized HDPE lined tubing in their field since April of 2002 to dewater gas wells. The liners are used in plunger lifted completions, beam pumped wells, and injection wells in this field in both 2 7/8-inch and 3 1/2-inch tubing. Several wells in this area have “S” shaped wellbores. Most significantly, this operator has realized significant cost reductions by reducing their pumping units down as much as two sizes without overloading their gearboxes because the TPL has drastically reduced the friction loading of the rods on the tubing. This operator had an unlined well fail twice (using new rods and tubing in each case) in less than one week after initial completion. HDPE lined tubing was installed in the well and it operated continuously for over three years before it was shut-in due to poor production volumes. Another well that was failing twice per year prior to using TPL tubing, ran for over six years seeing over twenty million rod pump strokes before evaluating the tubing with an ID caliper showing no measurable wear. This well also exhibited a dramatic reported reduction of over fifty percent in peak polished rod loads due to the liner, which improved lifting costs.

- Clearfork and Capitan Formations, Permian Basin, USA; Water Injection

- A major operator has been using HDPE, Western Falcon Enertube™, and PPS lined tubulars to inject produced water in over 100 wells since 2001 without any reported issues. Most of the tubulars are 2 7/8-inch with a lined drift ID of 2.000-inch. The typical well is approximately 1,000 meters (3,300 feet) deep and operates below 50°C (120°F) and at pressures below 210 bars (3,050 psi) injecting water with a chloride concentration of approximately 60,000 ppm.

- Midcontinent, USA; Deviated Production Wells

- A large independent operator in Oklahoma has used Falcon Enertube™ and Falcon Ultratube™ lined 3 1/2-inch L-80 tubing in 14 highly deviated horizontal wells. Prior to using TPL tubulars, the tubing failed in less than one month even using rod guides. These wells are approximately 2,300 meters (7,550 feet) deep and produce between 300 and 600 BFPD with approximately 85 percent of the fluid being produced water. The wells also produce approximately 400 MCF of gas per day. All wells are directionally drilled and the beam pumps are set in the horizontal section of the well. The build in the horizontal section of the well is between 15 and 20 degrees per 100 feet. Since initial installation of the lined tubing, this operator is enjoying run times exceeding two years and counting. The operator has reported that these wells could not be beam pumped if it was not for the TPL used in the tubing.

- South Texas, USA; Salt Water Injection

- Independent operator using Western Falcon Enertube™ lined 2 7/8-inch OCTG at a depth of 3,422 meters (11,230 feet) disposing of salt water at a rate of over 1,700 BPD at a pressure exceeding 324 bars (5,000 psi), at a temperature exceeding 85°C (185°F). This well has been operating daily without any issues for over two years.

- Louisiana, USA; Gas Production Well

- This operator installed Western Falcon Ultratube™ lined tubing in a well operating as deep as 3,400 meters (11,150 feet) in July of 2007. The well temperature is approximately 110°C (230°F) and operates at a pressure exceeding 170 bars (2,465 psi) producing 150 BPD of water and 700 MCF of gas per day that contains five percent carbon dioxide. This well is beam pumped with 2 7/8-inch L-80 tubing lined with PPS to mitigate corrosion and rod on tubing wear.

- Lloydminster, Canada; Oil Production

- A large Canadian operator has solved their tubing leaks by using HDPE lined tubing in over 30 wells in the Lloydminster, Canada area. The wells are primarily lifted using PC pumps with thermoplastic lined 4 1/2-inch J-55 tubing and operate at depths below 1,500 meters. The field produces heavy API oil with low water cuts. Prior to using TPL tubulars, the wells were averaging 7-month service life limited by tubing failures. The first thermoplastic lined well was installed in February 2007 and is still operating today. An increase in pump angle allowed by using lined tubing has increased the production rates in these wells.

- Permian Basin, USA; Sour Water Injection

- A large independent water flood operator has successfully installed over 41,000 joints of HPDE lined 2 3/8-inch and 2 7/8-inch OCTG in over 400 sour salt water injection wells since 2000. The average well depth is 1,000 meters (3,300 feet), the typical injection rate is 750 BPD at approximately 75 bars (1,090 psi), and the average temperature is below 40°C (105°F). The formation water has a chloride content ranging from 40,000 ppm to 125,000 ppm. In addition to lining the tubing, this operator also uses the same liner to protect his packers. Additional injection wells are still being completed weekly in this field with HDPE lined OCTG.

- Deviated Wells, South America: Production Wells in Waterflood

- A large international oil and gas producer has installed HDPE lined tubing in over 25 South American wells since October of 2007. The wells are completed using both PC and beam pumps in both 3 1/2-inch and 4 1/2-inch tubing. Prior to using lined tubing, the wells were failing every four to five months using bare steel tubing and rod guides. The field is a very mature waterflood that contains varying amounts of carbon dioxide.

- Rocky Mountains, USA; Corrosive Water Injection

- An oil and gas producer in the US Rocky Mountain region has been using Western Falcon Enertube™ lined OCTG in two water injection wells since January, 2006 and July, 2007. Both wells are completed using 2 7/8-inch tubing with a lined drift of 2.000-inches. These wells are injecting 9.5 PPG water containing 170,000-ppm chlorides with a pH ranging from 2 to 11. The water is very corrosive and has corroded holes in 316SS nipples in approximately 30 days. The pressure in these wells is over 240 bars (3,480 psi) and the temperature is approximately 99°C (210°F). All lined tubulars have performed without any incidents since installation. One well suffered a hole in an epoxy coated packer mandrel in January 2010 but the lined tubing was reinstalled and continues to operate in that well today.

- Nebraska, USA; Production Wells

- An independent oil company installed HDPE lined tubing in three test wells in Nebraska in September 2004. The wells were approximately 1,150 meters (3,800 feet) deep and lifted using beam pumps and sucker rods. Before lining the three wells were failing every 100 days due to a combination of corrosion, erosion and wear. The three test wells are all still in service without any tubing failures as of October 2012. At the time of this report, the TPL has extended the effective service life of the production tubing by over 30 times the life prior to using the liner.

- Ellenburger and Devonian Formations; USA; Acid Gas Water Injection

- This operator utilizes OCTG lined with Falcon Polycore™, Falcon Ultratube™, and Falcon Enertube™ in ten fields with the first installations occurring in 1999. While the lined tubulars are replacing failing ID thermoset coated tubing in the injectors, they are also used to solve rod on tubing wear issues in producing wells in the same fields. In one well, the operator has used HDPE lined 5 1/2-inch casing as the injection string at depths as great as 2,740 meters (9,000 feet) injecting between 12,000 BPD and 15,000 BPD. The well is on a 30-inch vacuum. The produced water contains high concentrations of both CO_2 and H_2S and between 65,000 ppm and 180,000 ppm chlorides. There are no reported failures in the lined tubing in these ten fields since the initial installation over eleven years ago.

- Wyoming, USA; High Solids Production Well

- A small independent operator in the Rocky Mountains was operating a very troublesome PC pumped well that would not run over thirty days without requiring a workover due to holes in the tubing from wear and corrosion. The well has a severe dogleg and produces large quantities of formation sand along with 1,300 BPD of fluid rotating at 65 Hz. After installing a string of HDPE lined 2 7/8-inch tubing, the well operated for over one year without requiring a workover. After one year, the pump was replaced and the same lined tubing was reinstalled in the well where it is still working today.

- South Texas, USA; PC Pumped Oil Wells

- One operator in Texas was operating two PC pumped wells that required four to five workovers per year to replace tubing that was wearing in his less than 1,000 meters (3,300 feet) deep wells. The operator opted to use Falcon Enertube™ in his wells because he was concerned about potential temperature issues from the use of hot oil in the field. The lined tubing was installed in March 2003 and is still in service today. The operator has already enjoyed an increase in service life of over 30 times that of bare steel tubing.

- Cherokee Formation, USA; Produced Water Injection

- A large international oil and gas producer has been replacing underperforming internally thermoset coated tubing with Falcon Polycore™ lined tubing in 18 produced water injection wells since 2007. The injection rates are approximately 1,100 BPD at temperatures between 50°C and 65°C (120°F to 150°F) and depths between 1,200 meters and 2,000 meters (3,900 to 6,550 feet). All of these wells are successfully operating today without a single incident since initial installation.

- Permian Basin, USA; Artificially Lifted Production Wells

- An independent operator has utilized HDPE, PPS, and Falcon Enertube™ liners in 23 different sour Permian Basin fields to solve corrosion and wear problems in production tubing. The wells range from 1,200 meters to over 4,000 meters (3,900 to 13,100 feet) in depth. Most of the wells are artificially lifted using reciprocating beam pumps. Prior to using TPL tubing, the wells were failing for tubing leaks every 150 to 400 days. Many of the liners have been in service since February of 2000. The operator has given several presentations detailing the cost savings they have realized by using TPL tubulars in their operations.

- Powder River Basin, Rocky Mountain Region, USA: CO_2 in Salt Water Injection Wells

- One operator has been using HDPE lined OCTG to protect their injection wells for over five years in the Powder River Basin. The first well was completed with over 2,150 meters (7,000 feet) of 2 3/8-inch tubing with a lined drift ID of 1.600-inch and has a maximum bottom hole temperature of 72°C (160°F). It is injecting salt water with dissolved CO_2 at a pressure of approximately 107 bars (1,500 psi). This operator has never had any operational problems with their TPL OCTG.

- Midcontinent Beam Pumped Well, USA; Production

- Due to corkscrew-like three-dimensional deviations in a well, an operator has started using Falcon Enertube™ lined 2 7/8-inch L-80 tubing to mitigate rod on tubing wear. This well operates with the reciprocating beam pump set at just over 4,000 meters (13,100 feet) deep and temperatures over 95°C (200°F) producing over 60 MCF of gas per day and less than 50 BFPD at a 40 percent oil cut and pressures over 160 bars (2,320 psi). The lined tubing has been in service in this well for over four years.

- Southern Saskatchewan, Canada; Oil Production

- Over fifty wells have been completed in this field using HDPE lined tubing. These wells produce fairly light API oil with high water cuts using primarily PC pumps. Unlined tubing used in conjunction with rod guides was failing in approximately nine months. Since November 2007 these wells have been completed using 3 1/2-inch HDPE TPL tubing and the liner has been operating without any problems for over forty months (over four times the previous service life). Previously, the operator was concerned about tubing wear and restrained their pump angle. Now, with TPL tubing, the operator has been able to increase the production capabilities of these wells by increasing their pump angle by over ten degrees.

8. CONCLUSIONS

With over fifteen years of successful documented operation under very extreme downhole production conditions, TPLs have proven to outperform other polymers in protecting OCTG from corrosion and abrasion. The ductility, thickness, and impact resistance of thermoplastics are able to handle most of the daily abuse seen on well servicing and drilling units. It is important to note that while TPLs have dramatically improved the damage resistance of OCTG polymer protection products, they are not indestructible and can be mechanically damaged when handled abusively or improperly. On the other hand, the success of TPL products in these mature producing fields around the world are an indication of how well they perform under the most extreme corrosive conditions when wear and abrasion are strong contributing factors to the root cause of tubing failures.

The ability of TPL liners to control rod on tubing wear in horizontal completions truly opens up a new set of opportunities to optimize the use of artificial lift in these wellbores that are becoming much more common today.

With a wide range of proven benefits like lower capital expenditure requirements, reduced tubular maintenance, corrosion control, improved flow characteristics inside the pipe, reduced pressure drop, and ease of installation, removal and reinstallation, TPL tubulars are still growing in their use both inside and outside of North America. The value proposition that TPL tubulars present include using existing equipment and installation methods with very few minor modifications to standard procedures resulting in the ability to install production tubulars in severely corrosive wells with extreme reliability and service life expectations measured in decades.

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1. SPE Paper 39815; "Polyethylene Lined Tubing in Rod Pumped Wells"; Eric C. Sirgo, Edward D. Gibson, William E. Jackson; Copyright 1998, Society of Petroleum Engineers, Inc.

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Table 1
Dimensions for Bare and TPL Common Tubing and Casing Sizes

Dimensions and Drift Diameter				Coupling OD			
(All values in inches)			Poly Lined	EUE 8rd		NUE 10rd	
Size	Tbg Wall	Bare ID	Drift	Regular	S. Clearance	Regular	S. Clearance
1.900" (1 1/2) 2.90#	.145"	1.610	1.250	2.500			
2 1/16" 3.25#	.156"	1.751	1.350			2.500	
2 1/16" 4.25#	.225"	1.613	1.200			2.500	
2 3/8" 4.70#	.190"	1.995	1.600	3.063	2.910	2.875	2.700
2 7/8" 6.50#	.217"	2.441	2.000	3.668	3.460	3.500	3.220
3 1/2" 9.30#	.254"	2.992	2.500	4.500	4.180	4.250	3.865
4 1/2" 10.50# Csg	.224"	4.052	3.500	5.000			
4 1/2" 11.60# Csg	.250"	4.000	3.500	5.000			
4 1/2" 12.60# Csg	.271"	3.958	3.400	5.000			
5 1/2" 14.00# Csg	.224"	5.012	4.500	6.050			
5 1/2" 15.50# Csg	.275"	4.950	4.400	6.050			
5 1/2" 17.00# Csg	.304"	4.892	4.300	6.050			
5 1/2" 20.00# Csg	.361"	4.778	4.200	6.050			

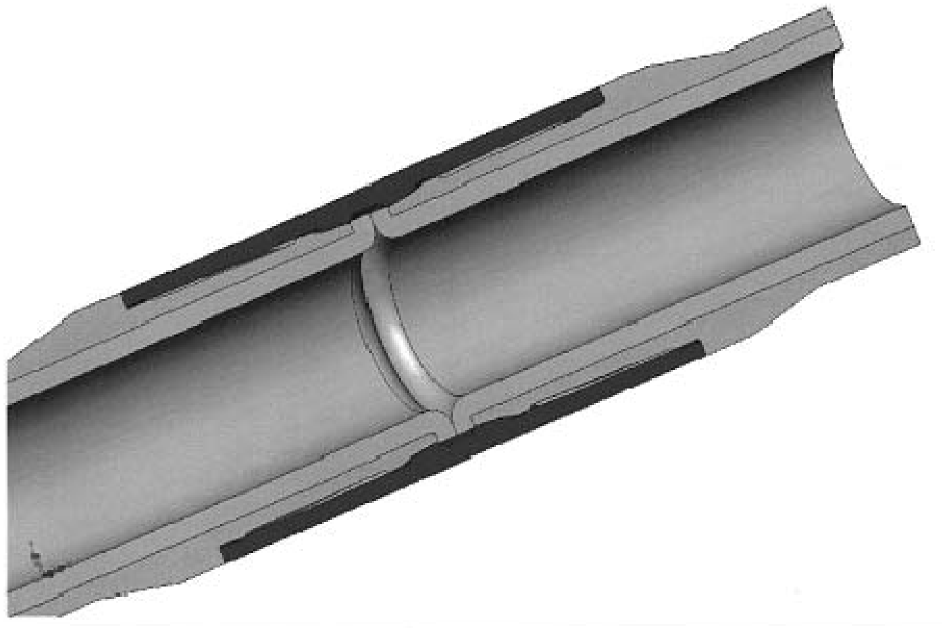

Figure 1 - Premium Connection with Thermoplastic Liner

Figure 2 - API Tubing Connection Lined with Engineering Thermoplastic