# Successful Oil and Gas Production Well Applications of Thermoplastic Lined Downhole Tubing: A Compilation of Case Histories Dating Back to 1996

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**ABSTRACT**

Thermoplastic liners are commonly used to protect 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 (CRA's), plastic coatings and thermoset liner products in extending tubular life. This paper compliments a recent paper focusing on water injection and disposal applications of the same liner products

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; yet, for more demanding environments, engineering thermoplastics such as PPS are available to handle temperatures as high as 175°C. In the most extreme production environments up to 260°C, liners made of PEEK are utilized. All of these polymers are significantly more flexible and impact resistant compared to traditional thermoset materials historically used to protect injection 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 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, PPS and PEEK. 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 sixteen specific case histories and production well environments.

Furthermore, to exhibit the overall economic impact of thermoplastic lined tubulars, a review of field installation and handling procedures will be presented as well.

The fundamental technical benefits of various thermoplastic lined tubulars will be covered with an emphasis on the proven extension of production tubing service life using thermoplastic liners.

## INTRODUCTION

### Types of Polymer Products Used to Protect Downhole Tubulars

### 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 polymer 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 probably be thermoplastic materials

## THERMOPLASTIC LINER SPECIFICATIONS

### Technical Data on Thermoplastic Lined OCTG

### 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 14,000 wells, HDPE liners are limited to a maximum temperature of only 71°C 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 100°C. 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 six years ago with the capability of operating in wells with maximum operating temperatures as high as 175°C. 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. While it is worth mentioning for high temperature severe service environments, the PEEK liner product is very 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 treating operations. At a minimum, the maximum pressure, maximum temperature, gas composition, liquid hydrocarbon composition, aqueous phase composition, and relative production rates for all produced fluids and gases 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 fluids or gases in the wellbore may actually reduce the allowable operating temperature and pressure for a liner.

## 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 polymer protection barrier compared to other materials. Additionally, thermoplastic materials are elastic and 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 1. The liners range in thickness from approximately 3 to 6 mm 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 and 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 9 mm on tubulars in this size range (see Table 1). A new lining machine (currently scheduled to be stationed in the Gulf States region) has been engineered by Western Falcon to line tubulars as large as 16-inch OD with the same thermoplastic liner products.

**Table 1. Dimensions for Bare and TPL Common Tubing and Casing Sizes (all values in inches).**

| Size | Weight | Tbg Wall | Bare ID | Poly Lined Drift | Coupling OD EUE 8rd Regular | Coupling OD EUE 8rd S. Clearance | Coupling OD NUE 10rd Regular | Coupling OD NUE 10rd 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 | | | |

**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 this 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 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 that pipe. He concluded 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: $1.5 \times 10^{-3}$ mm for the TPL ID surface versus $4.6 \times 10^{-2}$ 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 production wells can actually increase over time without any other changes in flow conditions.

**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 Western Falcon 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.

**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 rig floor) 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.

## 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 chemical resistance 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… Common methods to treat internal production tubing corrosion issues are thermoset coatings, GRE liners, corrosion inhibitors, biocides, oxygen scavengers, etc… When these 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 caused 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 many reasons including excessive wellbore deviation, rod friction or extremely corrosive fluids.

A recent study funded by ConocoPhillips evaluated the change in friction caused by the presence of TPL products inside of reciprocating rod pumped wells compared to bare steel tubing. The HDPE liner product was evaluated using a simulated laboratory apparatus at various side loads and under temperatures from 15°C to 75°C. A simple summary of this study is that the lined tubing reduced the friction of carbon steel "T" rod boxes to one-half to two-thirds of that experienced with bare steel tubulars. This data supports the reduction in peak polish 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.

## THERMOPLASTIC LINER CASE HISTORIES IN PRODUCTION WELLS

### Past Field Performance in Various Operating Conditions

#### i. Heavy Oil Production, South America

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 and at depths from 900 m to 1,500 m. 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.

#### ii. Artificially Lifted Wells, Alberta, Canada

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. 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 four 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.

#### iii. Directionally Drilled Wells, Pacific Coast, USA

This operator has installed over one million meters of TPL 2 7/8-inch and 3 ½-inch tubing in well over 500 beam pump and PC pump wells. A variety of different liner materials have been used including PPS, Falcon Enertube™ and 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, the liner was evaluated with downhole calipers and no measurable wear was found.

#### iv. McElroy Field, Permian Basin, USA

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. 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 detailing their success using TPL in this field.

### v. <u>Western Canada</u>

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 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.

### vi. <u>Colorado, USA</u>

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 ½-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 a 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 reduction of over fifty percent in peak polish rod loads due to the liner, which improved lifting costs.

### vii. <u>Midcontinent, USA</u>

A large independent operator in Oklahoma has used Falcon Enertube™ and PPS lined 3 ½-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 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.

### viii. <u>Louisiana, USA</u>

This operator installed PPS lined tubing in a well operating as deep as 3,400 meters in July of 2007. The well temperature is approximately 110°C and operates at a pressure exceeding 17,000 KPa 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.

### ix. Deviated Wells, South America

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 ½-inch and 4 ½-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.

### x. Nebraska, USA

An independent oil company installed HDPE lined tubing in three test wells in Nebraska in September 2004. The wells were approximately 1,150 meters deep and lifted using beam pumps and sucker rods. 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 July 2011. At the time of this report, the TPL has extended the effective service life of the production tubing by 25 times the life prior to using the liner.

### xi. Wyoming, USA

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.

### xii. South Texas, USA

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 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 25 times that of bare steel tubing.

### xiii. Permian Basin, USA

An independent operator has utilized HDPE, PPS, and Falcon Enertube™ liners in 25 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 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 and no failures have been reported in the lined tubing. The operator has given several presentations detailing the cost savings they have realized by using TPL tubulars in their operations.

### xiv. Midcontinent Beam Pumped Well, USA

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 deep and temperatures over 95°C producing over 60 MCF of gas per day and less than 50 BFPD at a 40 percent oil cut and pressures over 16,000 KPa. The lined tubing has been in service in this well for over three years.

### xv. Lloydminster, Canada

A large Canadian operator has solved their tubing leaks by using HDPE lined tubing in over 30 wells in the Lloydminster, Canada area. The majority of the wells are lifted using PC pumps with TPL 4 ½-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 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.

### xvi. Southern Saskatchewan, Canada

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 ½-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.

## CONCLUSIONS

With over fifteen years of successful documented operation under very extreme downhole production conditions, TPL 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 TPL 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.

With a wide range of proven benefits like lower capital expenditure requirements, reduced tubular maintenance, corrosion control, improving flow characteristics inside the pipe, reducing the 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 with extreme reliability and service life expectations in severely corrosive wells measured in decades.

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**FIGURES**

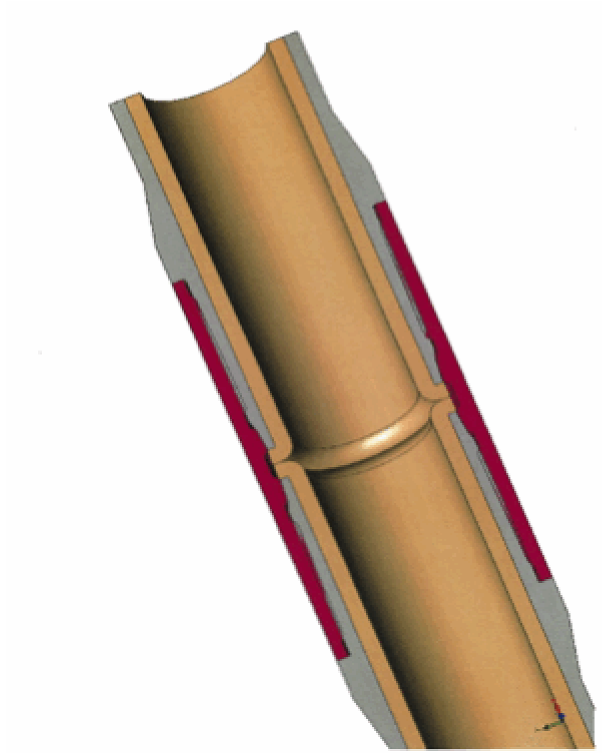

**Figure 1. Premium Connection with Thermoplastic Liner.**

**Figure 2. API Tubing Connection Lined with Engineering Thermoplastic.**