COATED CONTINUOUS ROD OPTIMIZES DEVIATED AND CORROSIVE WELLS

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ABSTRACT

The most common well profiles for reciprocating rod lift (RRL) applications in the Permian are deviated and highly corrosive wells. Many newly drilled horizontal wells exhibit moderate to severe deviations which require the pump to be set in the curve to produce intended target zones; resulting in a challenging environment for rod lift systems to successfully operate. These wells tend to be accompanied by corrosion, furthering the possibility of premature failures on all downhole equipment: rods, tubing, and pumps.

Several companies have worked to find a solution to these problems, with one simple product seemingly leading the way, continuous rod. In many wells such as these, continuous rod has proven time and time again that it can improve run life, reduce failures, and optimize production. Continuous rod has recently gone one step further by adding an epoxy coating to resolve the corrosion problem. Several wells have been field-trialed and have shown great improvements. This paper will provide an overview of the technology and the field improvements observed up to now.

Introduction

The use of pumping units in rod lift goes far back in history and become widely used in the oil industry in the mid-late 1800s[1]. From the beginning there have been advances in all kinds of lift technology. Sucker rods have carved out their own niche in the rod lift sector as being a cost-effective solution that is easily and quickly optimized.

As the industry and technology have advanced, wells have become more challenging. Operators are pushing the boundaries for more production in deeper wells; in turn, increasing loading conditions. Many of these deeper, more challenging, wells tend to have large deviations and are accompanied by a corrosive environment.

These attributes have demanded new approaches to how the rod lift sector handles wells. They are requiring high strength rods that work well in harsh environments and can handle a deviated wellbore. These types of wellbores increase wear on rods, couplings, and tubing. Traditionally the solution has been to add guides to sucker rods, made up of a variety of materials, to distribute sideloads and take on the wear caused by friction from constant contact with the tubing.

Continuous rod, a newer product in comparison, was developed as a more streamlined way to reduce flow losses in heavy oil applications, which subsequentially resulted in a new way to handle deviated wells. The addition of an epoxy coating offers a solution to extreme environments and opens the oil industry up to a revolution in technological advances for severe service applications. This paper aims to present the findings from field trials as well as review the aspects that make continuous rod a prime choice for deviated, corrosive, and deep wells.

Basic Design Concepts of a Deviated Well

A deviated well is defined as “the angle at which a wellbore diverges”[2]. This can be done deliberately to “increase exposure zone to producing zones, intersect a larger number of fractures, or to follow a complex structure”[2]. Sucker rods are used in reciprocating rod lift wells to produce wells that are closer to their end of life. “The objective of a sucker rod string is to transmit reciprocal motion of the pumping unit to the pump plunger at the bottom of the well, causing it to move fluid from the wellbore into the pump barrel and discharge it through the pump into the bottom of the tubing at a pressure that allows the fluid to flow to the surface"[3]. Sucker rod designs are used to predict how much fluid can be pulled from a well in certain parameters. These designs vary from company to company and even design engineer to production engineer. Some of the most influential aspects in a design are the deviation survey, side loading, fluid properties, and sucker rods themselves.

The biggest piece of the puzzle that can change any sucker rod design is the wellbore survey. The survey is meant to describe a well through completed measurements of inclination and azimuth. These surveys will be entered into a software to create a computer-generated image of what the wellbore looks like. The more accurate a survey, the better the software will be able to predict how the string design may handle places in the wellbore where the geometry changes rapidly in a three- dimensional space. The image of the wellbore produced by the software is then interpreted by the software to display potential forces placed on the rods in particular areas, known as sideloads. The software estimates side forces on the rods in areas of bending and recommends guide placement.

The general rule of thumb for how many guides to run in certain areas of sideload also varies; some companies guide based on sideload while others guide based on inclination. For the purposes of this paper, assume any area of inclination that exceeds three degrees requires the rods to be guided. From there the number of guides per rod will depend on a multitude of factors, none of which are pertinent to the purpose of this paper.

While each guide added to a sucker rod reduces the wear on the sucker rod body, it also increases the friction applied to the rod string. Continuous rod utilizes the same premise of guided rods, reduce rod wear, while keeping friction forces the same or slightly less than that of a bare conventional rod. The biggest difference between continuous rod and conventional stick rod is the loading distribution. Conventional rods have a few contacts points with which to distribute sideloading, the couplings and guides, if added. In certain cases, where deviation is severe, the conventional rod body may end up laying on the tubing causing wear on the tubing and rod itself. Continuous rod can distribute the load across the entirety of the string evenly by eliminating couplings and guides (Figure 1). This is done by welding different taper sizes together, compared to the male/female connector relationship of couplings and pin ends. This extends the run life of the rods as well as the tubing.

Continuous rod comes in two different cross-sections -round or semi-elliptical- as well as a variety of different sizes and metallurgies. Through field and lab results, the semi-elliptical rod has been the primary choice for RRL designs; this paper will focus on semi-elliptical rod. Semi-elliptical rod allows for additional load distribution through its unique shape. This product was designed to fit inside the contour of the production tubing (Figure 2). The geometrical change, along with the elimination of connections every twenty-five to thirty feet, translates to lower wear rates for the rod string and tubing[4].

Semi-elliptical rod has been installed in hundreds of wells throughout the continental U.S. as a primary way to handle heavily deviated rod lift applications. Continuous rod comes in sizes ranging from 1.125" – 0.875" in increments of 0.0625". The smaller increments in taper sizes directly transfers into the weight of the string. In a typical deviated well that would require being fully guided, continuous rod is approximately eight percent lighter in comparison to that of conventional rod. This can be used as an advantage in some cases by reducing the loading on the entire system: unit structure, gearbox, etcetera.

Like conventional rods, continuous rod comes in low strength, mid strength, high strength, and ultra-high strength that can all be utilized based on the well parameters. Much like conventional rods the differing rod grade/strength can be greatly be affected by corrosive properties the well may have. Corrosive environments can result in material loss (reducing load capacity) and stress risers ending in rod failure. Corrosion can be controlled with chemical inhibition programs, but in some cases, this option is too costly or does not perform as well as intended. Challenging environments like this called for a new product on the market, coated rod.

Coated Continuous Rod Lab Testing and Field Selection Criteria

Coated continuous rod utilizes an add on product of a dual layered epoxy system. This is a powder coating that is fusion-bonded to the continuous rod base steel material. The dual-layer coating is used to protect the steel substrate from production fluids and metal-on-metal contact.

The first layer of coating is used to completely cover the continuous rod and ensure there is no production fluid contacting the steel, eliminating possible corrosion to the rod string. The primary function of the second layer is protection, as it is used to cover the first layer; an added benefit is its ability to offer a degree of rod/tubing wear protection. In some cases, the coating has produced a reduction in polished rod loads pointing to the possibility of a smaller coefficient of friction than that of bare rods, future lab studies will be conducted to confirm this and try to quantify it. Qualitive tests were performed to ensure the coating is the optimal choice for corrosive applications.

Profile Testing

For the fusion bond epoxy to adhere properly, an irregular or roughened profile must be created on the steel surface. This test ensures proper surface anchor profile prior to the coating application. This is done by grit blasting the material to increase total surface area, increasing adhesion properties. Thickness is measured through negative surface impression on a crushable layer of plastic microfilm coated onto a polyester film of uniform thickness. When the material is compressed against the grit blasted surface the film with replicate the details of its roughness. This is then placed into a device that reads the measurement. The measurement is verified that it is within material specifications.

Thickness Testing

Measurements of coating thickness are used to indicate thickness tolerances to produce the optimal properties required of coated continuous rod.

Bend Testing

Samples were placed into a 3-point bend system to test strain and ensure the coating is adequately flexible, has good adhesion, and is fully cured.

Holiday Detection

A wet sponge was used as a medium to complete an electrical circuit wherein an alarm will sound if contact between the steel and sponge is made. A visual inspection was also completed to verify there were no pinholes or cracks to the visible eye. Continuity of the material assures that no corrosion is able to contact the steel.

Cathodic Disbondment

A hole was etched into the coating on a sample portion of continuous rod and was then placed in a heated salt solution and connected to an apparatus that transmitted current for a set amount of time. This tested the adhesive properties of the coating on the grit blasted surface.

Reciprocating Wear

A sample of coated rod was placed inside a section of tubing where force, replicating sideload, was applied to determine the run life of coating. Test results suggested the run life of the rod string was increased by adding the coating. The coating on the rod suspends tubing wear on the steel rod underneath until the coating is fully worn off. Afterwards the wear on the steel rod reacts as it would if there had never been coating.

Field Selection Criteria

Wells selected for field trials were those that had severe deviations and multiple interventions due to aggressive corrosion; wells with high levels of hydrogen sulfide (H_2S) and carbon dioxide (CO_2). The rod string failure history was supplied by the customer to give a background of past failures: identification of root cause of failure and previous run times. Each well was evaluated and given a target expectation, Key Performance Indicator (KPI). A majority of the KPI's selected were to run, at minimum, two times the mean time between failure ratio (MTBF).

Once the KPI's were set the string was installed and active run time was tracked. The run time was based on the active time the string was in the well, the clock was only stopped in situations where a rod string failure occurred. Any workover other than that was not considered to affect the life of the rod string. To provide a comparison wells were selected in a few different regions, however this paper will focus on those that were selected in the Permian Basin.

Field Trials

The Permian Basin is regarded in the oilfield industry as one of the areas with the most corrosive and highly deviated wells, making it the perfect subject region for field trials. Figure 3 showcases the MTBF for each well trialed. As stated previously, the MTBF was measured based on the number of days the rod string ran in the well from first install up until the first rod failure intervention. The run times of the rod string before coated continuous rod are shown in orange, while the run times shown in blue represent the coated continuous rod run time. It should be noted that the run times for active strings reflected below end the day this paper was submitted (July 2021). The graph shows a significant difference between the previous rod string and the coated continuous rod. Most of these wells resulted in failure due to corrosion or deviation related causes. Details of conditions and trial results are detailed below.

Well A had a requested pump depth of 6,300 ft., for coated continuous rod, which set the pump below the kick-off-point (KOP) at a twenty-five-degree angle of inclination. The resulting side loads were over 150lbs with moderate H_2S concentration levels. The surface equipment utilized on this well was a conventional 912-365-168 pumping unit with a stroke length of 168" running at 7SPM (strokes per minute). The original downhole equipment consisted of a 1.75" insert pump and non-API special service high strength guided steel rods. This set up was run with the pump seated above the KOP and had a MTBF of 639 days. This rod string was replaced with D-1536M semi-elliptical coated continuous rod and set below the KOP. This replacement is still active with no rod failures to date, surpassing the previous runtime with a MTBF of 998 days (Figure 4).

Well B has a pump depth of 6,230 ft. with high deviations and sideloads over 250lbs. The surface equipment utilized was a conventional 456-305-144 pumping unit with a stroke length of 103" running an average of 6.5SPM. The downhole equipment was a 1.50" insert pump with steel continuous rod. This design had a MTBF of 658 days. This well's main challenge was frequent tubing failures due to deviation. It is noted that this well did not have a significant amount of corrosion failures, however the application had an environment that was corrosive enough to require the use the coating, which is why it was added to these field trails. DE-4120M semi-elliptical coated continuous rod was combined with poly-lined tubing to further reduce the possibility of tubing failures. This replacement is still active with no rod failures to date, surpassing the previous runtime with a MTBF of 953 days (Figure 5).

Well C has a pump depth of 6,650 ft. with a fairly straight wellbore. The main concern with this well was high H_2S concentration levels in combination with bacteria. The surface equipment utilized for this well was a conventional 640-365-144 pumping unit with a stroke length of 121" running an average of 6.7SPM. The original downhole equipment was a 1.50" insert pump with steel conventional rod. This design had a MTBF of 90 days due to corrosive environment. This string was eventually replaced with D-1536M semi-elliptical coated continuous rod which is still active with no rod failures to date, surpassing the previous runtime with a MTBF of 914 days (Figure 6).

Well D had a proposed pump set depth lower in the KOP at 6,400 ft. near a forty-degree angle of inclination with side loads over 250lbs. This well had deviation challenges and it contained high concentration levels of H_2S. The surface equipment utilized was a long-stroke 350-360-288 pumping unit running at an average speed of 3SPM. The downhole equipment utilized for the RRL application was a 2.00” insert pump with the previous set up being an ESP. Upon failure the ESP was replaced with D-1536M semi-elliptical coated continuous rod. This design is still active with no rod failures to date, surpassing the previous runtime with a MTBF of 912 days.

Well E has a pump set depth of 9,000 ft. The concern with this well was the high concentration levels of H_2S. Surface equipment for this well was a conventional 640-365-144 pumping unit running at an average speed of 7.6SPM. The downhole equipment was a 1.75” insert pump with conventional steel rods. Due to corrosion the previous steel string only had MTBF of 273 days. This string was replaced with ME-4120M semi-elliptical coated continuous rod, which is still active with no rod failures to date, MTBF 727 days (Figure 7).

Well F has a pump depth of 4,300 ft. with challenging deviations in the upper section of the wellbore, sideloads are over 300lbs. The surface equipment utilized is a long-stroke 350-360-288 pumping unit running an average speed of 4SPM. The downhole equipment was a 1.75” insert pump with steel conventional rods. This design had three rod parts in a year due to deviation, resulting in a MTBF of 127 days. This string was replaced by DE-4120M semi-elliptical coated continuous rod and is still active with no rod failures to date, MTBF 563 days (Figure 8).

Well G has a pump depth of 4,750 ft. set below the KOP at a forty-eight-degree angle of inclination with sideloads over 300lbs. The surface equipment utilized for this well was a conventional 912-365-192 pumping unit with a stroke length of 168” running at 5.5SPM. The downhole equipment was a 2.00” insert pump and steel conventional rods. A combination of corrosion and deviation challenges lead to the failure of this rod string with a MTBF of 48 days. This is string was replaced by DE-4120M semi-elliptical coated continuous rod and is still active with no rod failures to date, MTBF 473 (Figure 9).

Well H has a pump depth of 3,100 ft. set pump below the KOP at a thirty-degree angle of inclination with sideloads over 200lbs.This well has deviation challenges as well as high concentration levels of H_2S and bacteria. The surface equipment utilized for this well was a conventional 640-365-168 with a stroke length of 168” running at 8SPM. The downhole equipment was a 1.50” insert pump with conventional steel rods. These rods failed due to corrosion and deviation issues resulting in a MTBF of 77 days. This string was replaced with DE-4120M semi-elliptical coated continuous rod and is currently active with no rod failures, MTBF 266 (Figure 10)

Conclusion

Coated continuous rod has proven its ability to out-perform other rods in corrosive and deviated applications, and in some cases produced a run life nine times that of conventional steel rods. The combination of the uniquely semi-elliptical cross-section, with the elimination of couplings, and addition of corrosion resistant coating has shown longer run times on the wells presented in this paper. The operational advantages provided by coated continuous rod have extended the run times of the wells in this paper; a lighter rod string, reduction of frictional forces, and elimination of corrosion attack.

Coated continuous rod is an excellent choice for challenging RRL wells and should be considered any time a well has had multiple interventions. It has reduced workover costs, increased production, and breathed new life into wells previously thought to be unpumpable due to deviation or corrosion.

Reference

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3. Bommer, P. M., Podio, A. L.(2015). *The Beam Lift Handbook.* The University of Texas at Austin.

4. Fregene, Chainomi S. “Operational Advantages of Semi-Elliptical Continuous Sucker Rod in Reciprocating Rod Lift Applications.” SWPSC 2020, Accessed 15 June 2021.

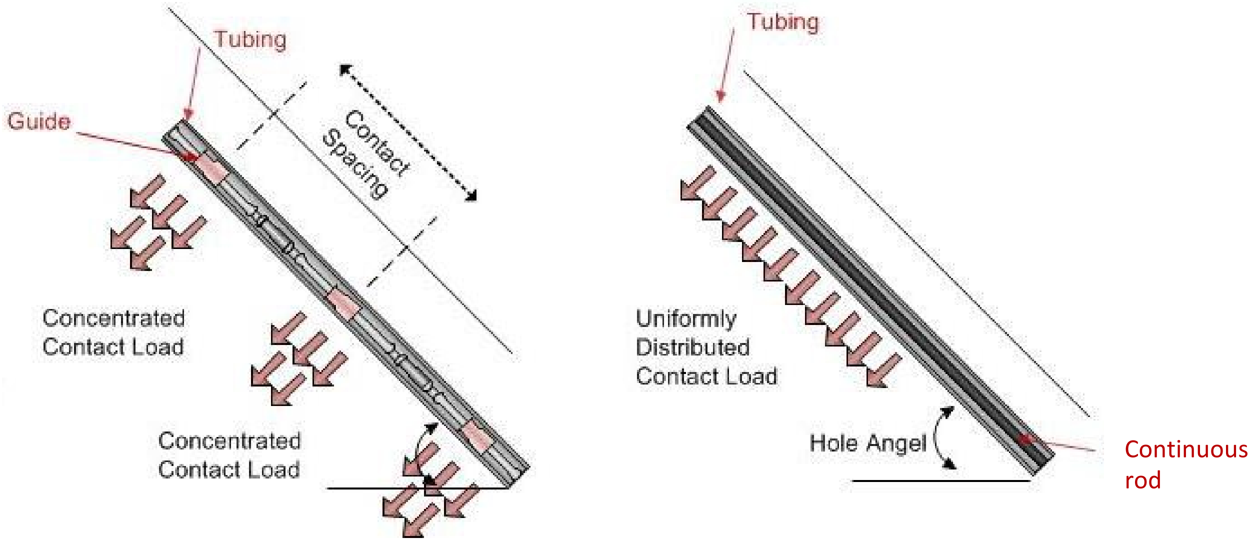

Figure 1- Continuous rod (right) uniformly distributes the sideload across the entire length of the rod string, reducing the coefficient of friction. Conventional rod systems (left) have several concentrated points, couplings and guides, to distribute the sideloads, resulting in heavier loads at those points. A lower load uniformly distributed between rod and tubing extends the run-life of both.

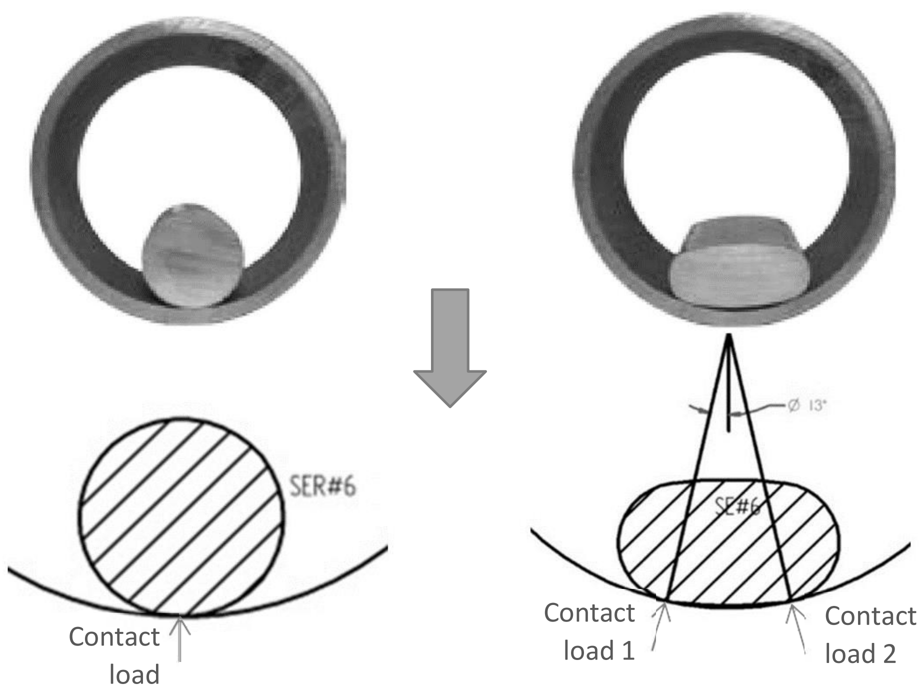

Figure 2 – For the semi-elliptical rod (right), the applied contact load is distributed between two normal, symmetrical contact points on the tubing surface. Compared to the contact for a continuous round rod (left), the semi-elliptical's dual contact points will significantly reduce the contact loads for both the rod and tubing.

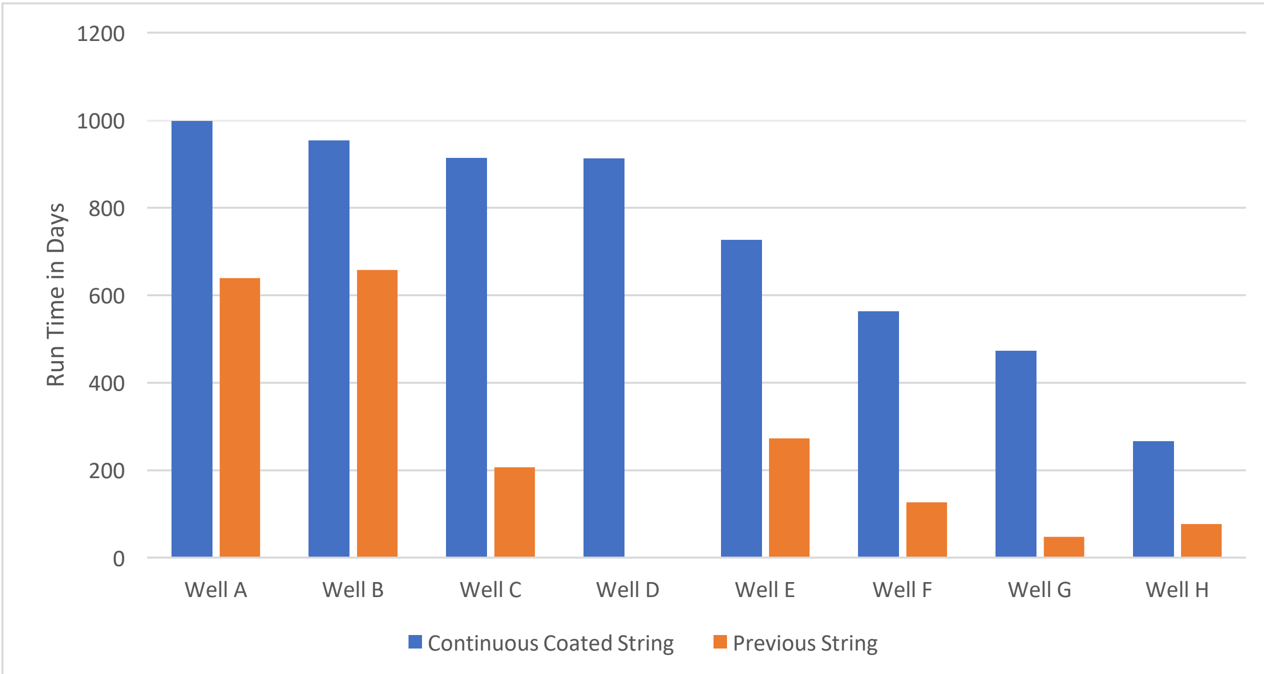

Figure 3 – The run life of the continuous coated rod exceeds that of the previous strings run in trialed wells from the Permian Basin.

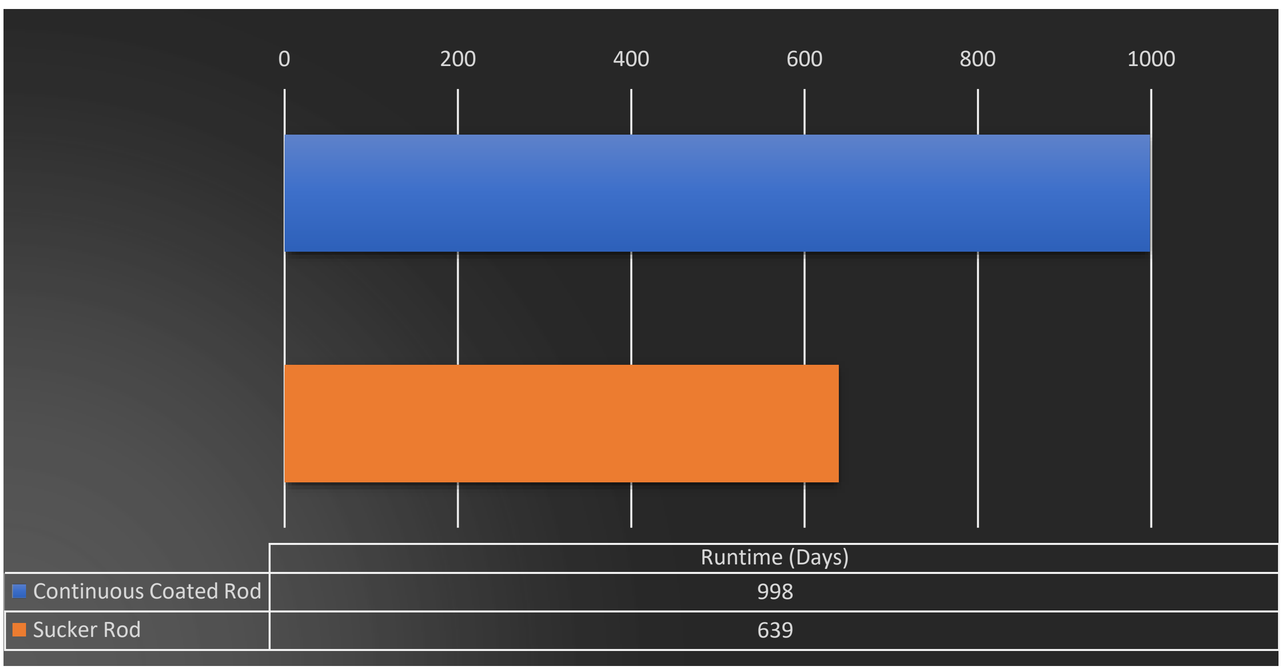

Figure 4 – **Well A** ran 1.5X longer utilizing continuous coated rods compared the guided conventional steel rods.

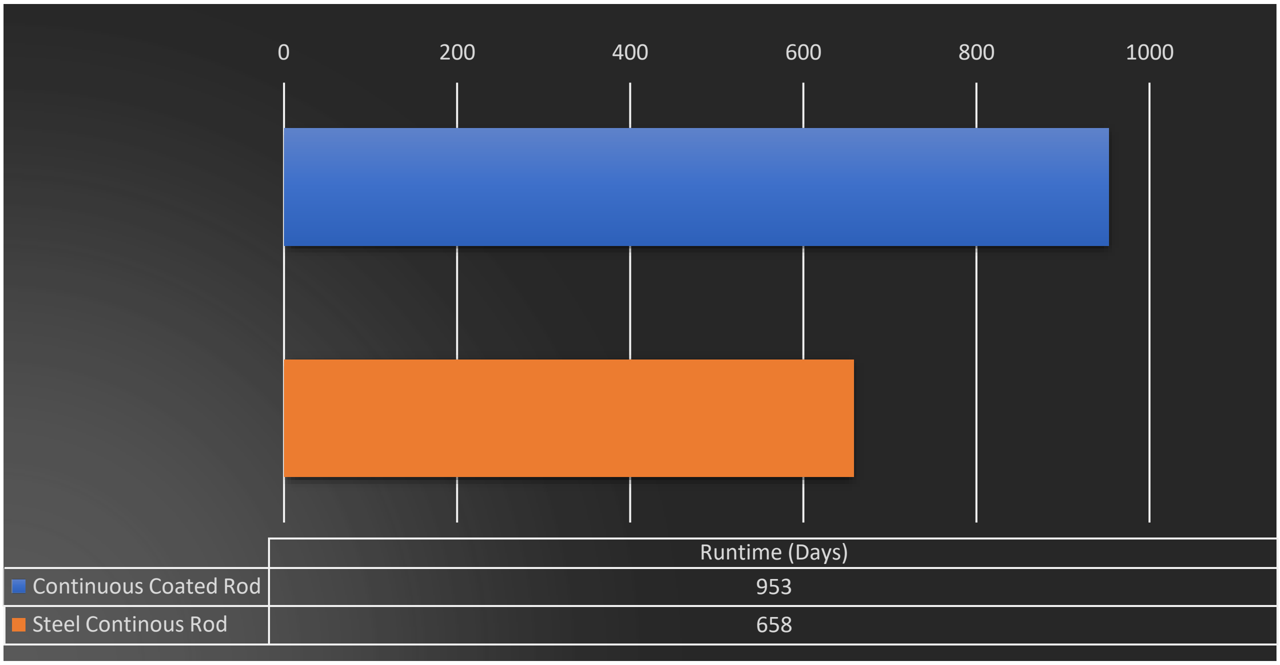

Figure 5 – **Well B** ran 1.4X longer utilizing continuous coated rods compared the continuous steel rod.

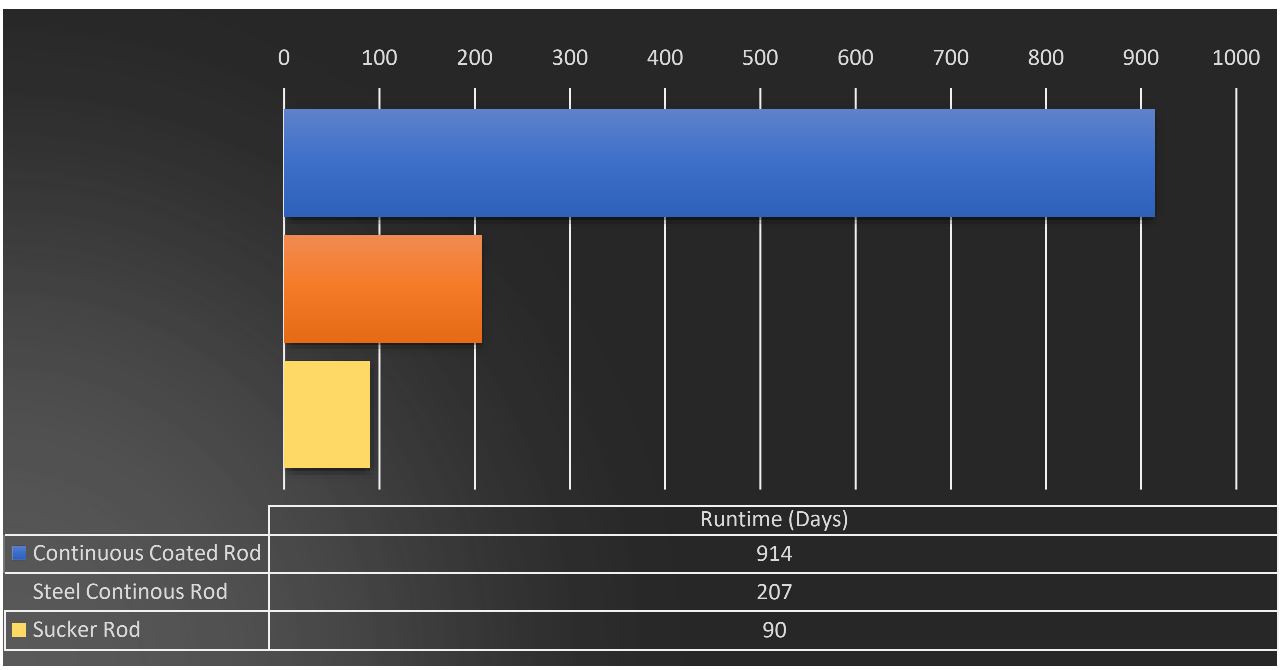

Figure 6 – **Well C** ran 4.4X longer utilizing continuous coated rods compared the continuous steel rod and 10X longer than that of conventional sucker rods.

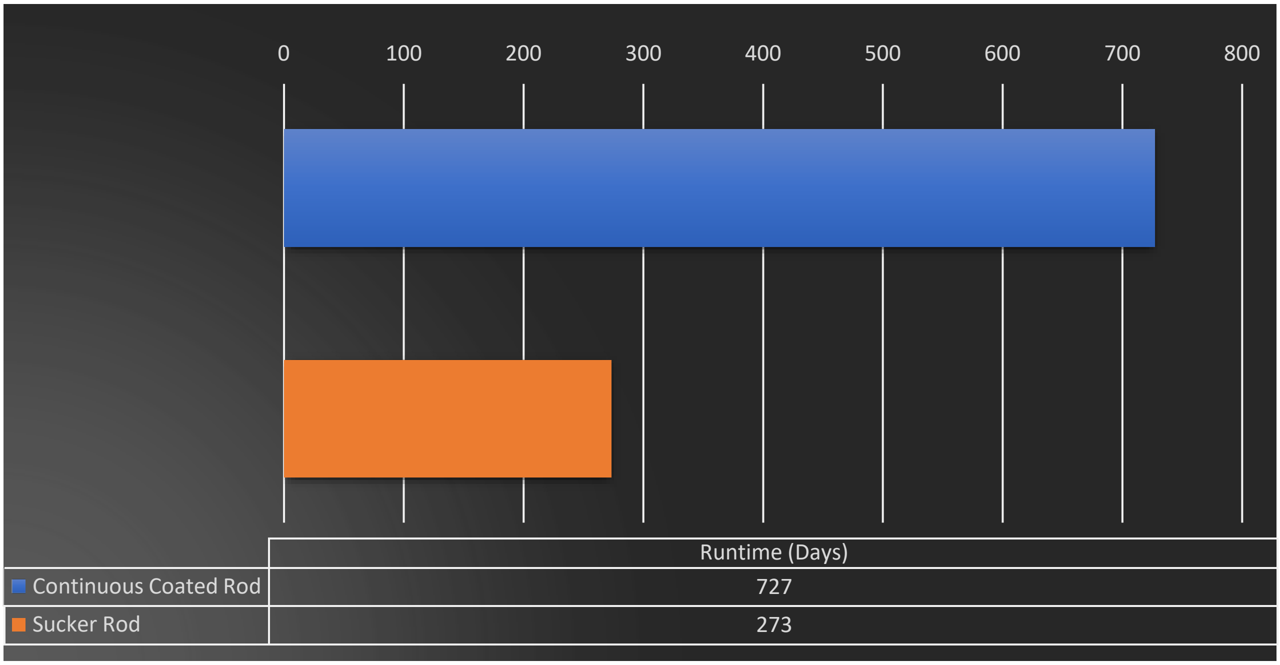

Figure 7 – **Well E** ran 2.6X longer utilizing continuous coated rods compared the conventional sucker rods.

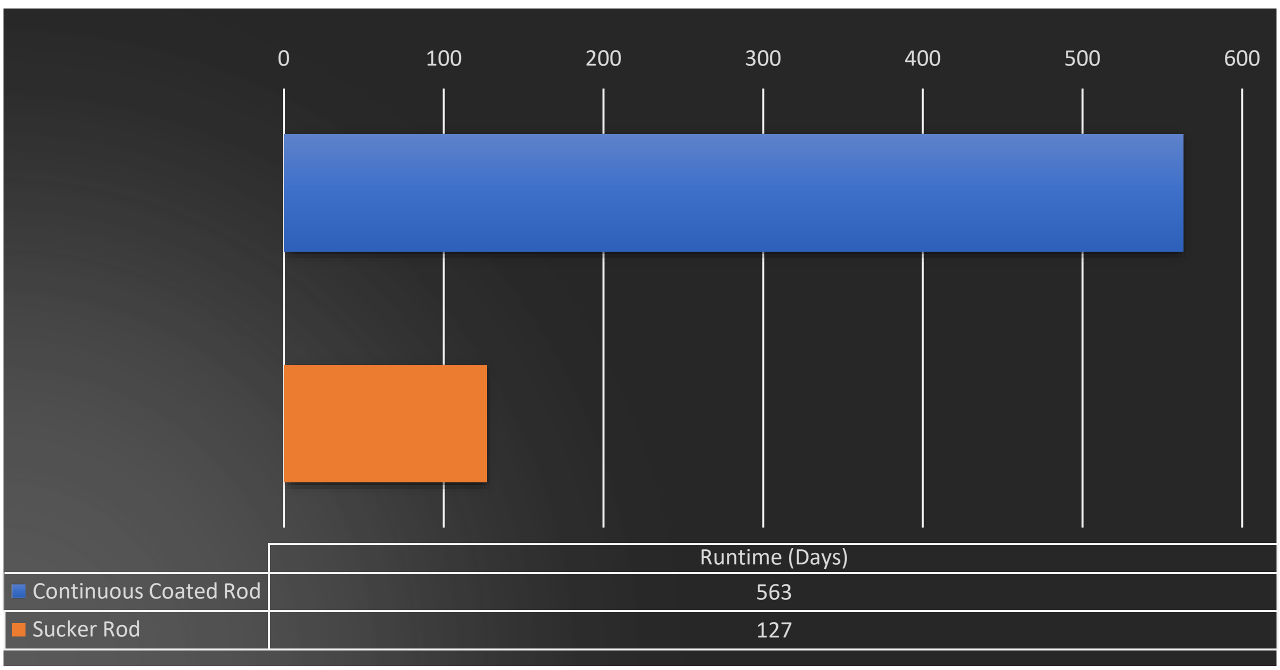

Figure 8 – **Well F** ran 4.4X longer utilizing continuous coated rods compared the conventional sucker rods.

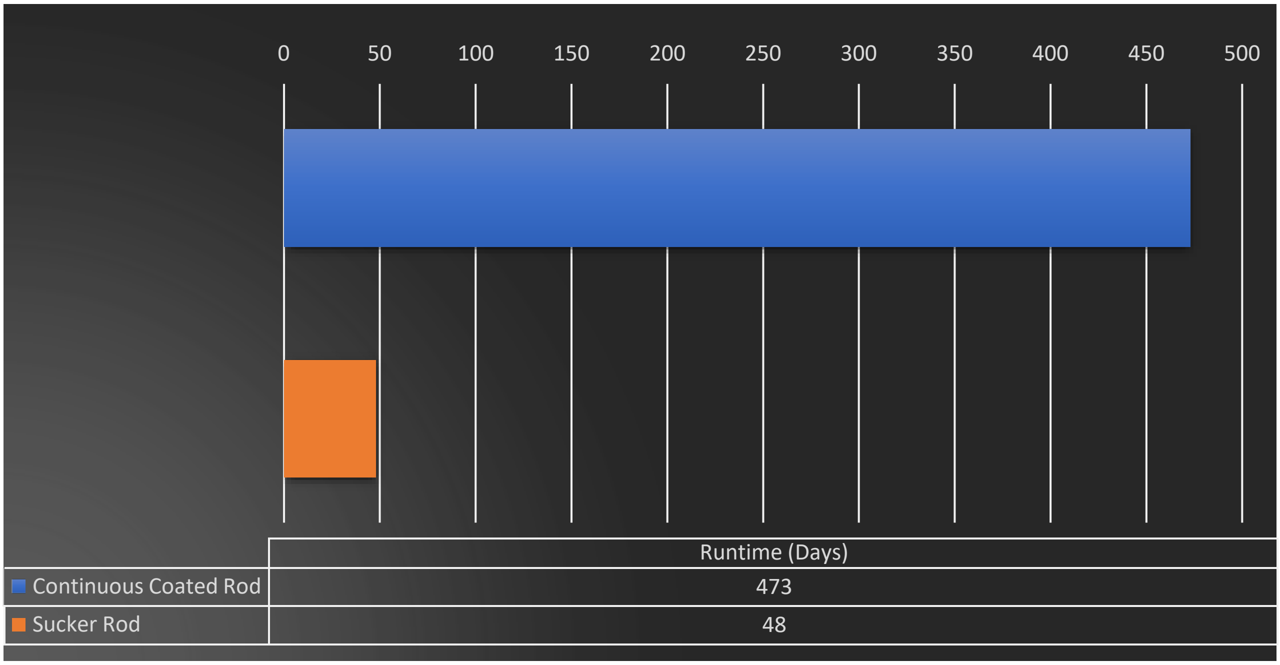

Figure 9 – **Well G** ran 9.8X longer utilizing continuous coated rods compared the conventional sucker rods.

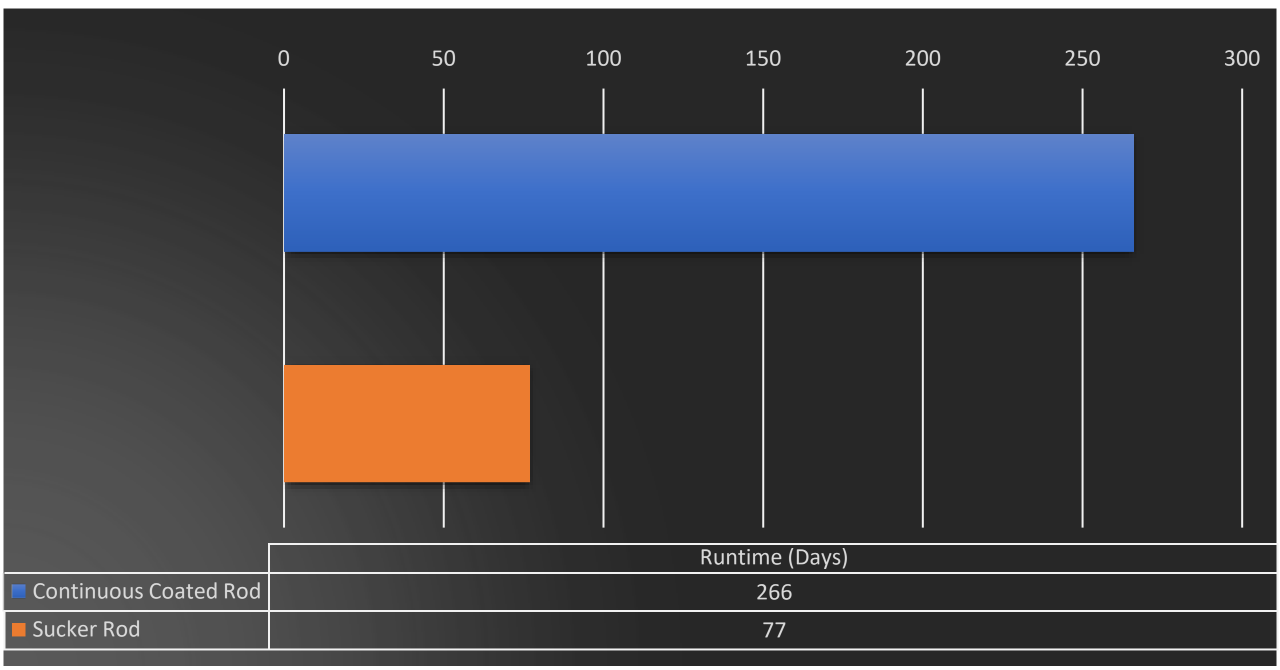

Figure 10 – **Well H** ran 3.4X longer utilizing continuous coated rods compared the conventional sucker rods.