CONTINUOUS ROD: IMPROVING RUN TIMES IN UNCONVENTIONAL WELLS

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Unconventional wells are drilled in shale formations to produce oil and gas utilizing horizontal drilling and hydraulic fracturing. Many think fracturing creates a ‘rubble zone’ around the wellbore allowing the free oil and gas to be produced.

Unconventional wells are generally drilled “vertical” and then “kicked-off”, building the curve and then continuing to drill horizontally at a targeted distance through the layer of oil-bearing rock. Due to the intentional and unintentional dogleg severity that occurs throughout the drilling process, extreme side loading conditions are created when rod pumping. S curve wells are common unconventional wellbore trajectories that present challenges when rod pumping.

Due to the rock properties of shale formations, wells with long laterals through the pay zone are completed. This results in large production volumes with exponential decline. As these wells begin to decline, artificial lift is needed to continue to effectively lift fluid to the surface. Rod pumping is usually the preferred artificial lift method for liquid rich wells.

This paper focuses on the sucker rod string as it delivers the energy created at surface to the downhole pump. The sucker rod string typically consists of steel sucker rods, connected by couplings every 25 feet, to mechanically lift the fluid from the downhole pump.

Unfortunately, the complex trajectories of unconventional wells create mechanical friction between the rods and tubing resulting in extreme side loading conditions. This leads to rod parts or tubing leaks from extensive wear of the contact area between the couplings/rods and tubing. The force or side load is often concentrated on conventional rod’s couplings, increasing the pressure between the rod and tubing string. This leads to an increase in failure rates.

Continuous rod is a viable solution for deviated wells because of the lack of couplings, the side load is distributed over an increased area of contact. This results in longer run times.

This paper presents results from five high failure rate wells that were converted from conventional sucker rod to continuous rod due to failures caused by downhole deviation.

HISTORY OF CONTINUOUS ROD

Continuous rod was originally developed in the early 1970’s in Canada and still enjoys widespread use today. In the early 1980’s, progressive cavity pumps, or PCP’s, were adopted as a viable form of lift for heavy viscous crude. Canada, California, and Venezuela quickly began to implement PCPs in these formations utilizing continuous rod to turn the pump.

Today, continuous rod is still predominantly used with PCPs in high viscous fluid formations, but conventional sucker rods remain the primary form of rod conveyance in rod lifted wells. However, due to the challenges posed by directional drilling, continuous rod is being installed more frequently to reduce failures caused by deviation in rod pumped wells. Currently, there are two continuous rod shapes manufactured: round and semi-elliptical. Round is the more widely adopted shape for deviated shale wells.

Because continuous rod is a continuous string of steel, it is stored on six-meter reels and installed with a truck mounted injector (TMX), see Figures 1 and 2.

Historically, two barriers have limited the use of continuous rod: lack of serviceability and unreliable field forge welding. With modern technology and service adoption, continuous rod is becoming a competitive rod string option in deviated rod pumped wells, as it is proven to increase the meantime between failures. Continuous rod is offered in alloys comparable to conventional rod: chromium-molybdenum alloyed steel and chromium-molybdenum-nickel alloyed steel both in D and high strength grades.

This paper will focus on the benefits of continuous rod in deviated environments and the resulting improved run times.

MANUFACTURING CONTINUOUS ROD

Continuous rod strings are comprised of steel coils that are approximately 2,000 to 3,000 feet in length depending on the size of the rod. These coils are welded together and straightened into a 9-meter reel prior to being heat treated to grade.

The first step in heat treating continuous rod is austenizing. Austenizing is a heat-treating process of heating the steel in an oven to above its critical temperature for transformation to occur. The second step in the heat-treating process is quenching the steel. The steel, or rod, is rapidly cooled with water to harden the steel to a martensite structure. The next step is to temper the rod to grade in a tempering oven, either to D grade or high strength grade rod.

After the three-step process above, some manufacturers may shot peen the rod to improve the overall surface tension of the steel. This is also known as creating an induced compressive stress layer to increase resistance to fatigue failures. Shot peening helps resist the development and retard the propagation of fatigue cracks. The resistance to fatigue failures suggests shot peened continuous rod will perform better in corrosive environments than continuous rod that has not been shot peened.

CONTINUOUS ROD ADVANTAGES

Reduced Wear:

As mentioned above one of the main challenges associated with shale wells is deviation. During the cyclic pumping operation, the rods and couplings rub against the tubing producing tubing failures, rod parts, and coupling breaks, which increases operating expenses.

Common practices in the industry to remedy downhole friction include sucker rod guides, spray metal sucker rod couplings, and roller rod guides.

Sucker rod guides are “sacrificial” in the sense that they absorb the wear between conventional rods and tubing, therefore decreasing the wear on couplings and rods. However, sucker rod guides can increase the friction between the rod and the tubing string which can result in higher loads on the rod string reducing its fatigue life, see [2]. Also, the increase in friction, can require greater power requirements at surface. Sucker rod guides can also wear out quickly, particularly in high side load wells.

Spray metal sucker rod couplings are made of hard corrosion resistant metal powder-based alloys such as nickel which are sprayed on the outer diameter of the couplings. Spray metal couplings can reduce the overall friction of the rod string but are sometimes avoided because they can accelerate wear on a softer tubing string.

Roller sucker rod guides can be used to extend run times in low side load wells but can create issues in high side load wells. The high side loads can cause the wheel axels to break apart and therefore are not a preferred solution for severely deviated wells.

An alternative solution to downhole friction is the use of continuous rod. Continuous rod strings only have one connection at the top and one connection at the bottom of the string, eliminating couplings every 25 feet.

The weakest links of a conventional sucker rod string are the connections. The connections are responsible for many of the downhole rod failures including fatigue breaks, erosion from constant contact with the tubing in deviated sections of the wellbore and loosening of the connections from fluid pound or improper makeup. Continuous rod eliminates the above-mentioned problems associated with pin and coupling failures due to the lack of connections.

This makes continuous rod well suited for deviated wells because the side load is evenly distributed over a greater area rather than being concentrated on the couplings. Furthermore, since continuous rod is lighter than a conventional rod string, the magnitude of the side load incurred will be reduced. Also, in a conventional sucker rod string, the restriction in area imposed by using couplings creates turbulent flow which results in fluid friction losses. In continuous rods, these losses are eliminated, see [3, 4].

As mentioned above, when using continuous rod, less mechanical friction is experienced by the rod lift system. This difference in mechanical friction is even greater when comparing rod guides to continuous rod to mitigate problems created by deviation. As explained in [10], mechanical friction results in a loss of downhole pump stroke, resulting in less production. Therefore, installing continuous rod decreases failures through less wear and can potentially increase production with a longer downhole stroke.

As stated above, one of the advantages of continuous rod is improved performance in deviated wells where mechanical friction between the rod and the tubing strings leads to premature failures.

Abrasive wear is defined as “wear in which hard asperities on one body penetrate the surface of a softer body and ‘dig’ material from the softer surface, leaving a depression or groove”, cf. [2].

Continuous rod will abrade the tubing along the entire length of contact as opposed to a concentrated force acting on the couplings, cf. [1].

In the case of a conventional rod string, because the coupling has a larger diameter than the rod body, the contact force is concentrated on the couplings, following the concept of a centralized force or pinch point. In the case of continuous rod, because there are no couplings, the contact force is spread out over the entire area of the surface contact area of the continuous rod string and tubing string. Because the force is spread over a greater area, the pressure the force applies is less per unit area. This results in significantly less wear. A diagram showing the difference in the contact areas of a conventional rod string versus a continuous rod is represented in Figure 3.

Normal Force and Pressure Analysis:

Continuous rod is designed to disperse side loads along the length of the rod creating a larger area of contact for the rod on tubing side loads, as seen in [2]. The decrease in mechanical wear between the rods and tubing with continuous rod can be attributed to the fact that conventional rods contact the tubing along the length of the coupling alone, due to the greater outside diameter difference between the sucker rod body and the couplings, see [11].

Also, due to its lighter weight, continuous rod results in a smaller normal force than a conventional rod string. The difference in weight between a conventional rod string and a continuous rod string is displayed in Table 1.

The equation for the normal force is given by:

$$F_N = L_r \cdot W_r (1 - 0.127 \cdot \gamma_F) \sin \alpha, \tag{1}$$

Where F_N is the normal force (lbf), L_r is the length of the rod string (ft), W_r is the weight of the rod string (lb/ft), γ_F is the fluid specific gravity and α is the inclination angle (degrees). The normal force is proportional to the weight of the rod, therefore, the lighter the rod the smaller the normal force will be.

Pressure is defined as the results of a force acting on an object over a certain area. Wear is the direct result of the applied pressure to the rod or tubing. The equation for pressure is the force divided by contact area as given by:

$$\sigma = \frac{F_N}{A}. \tag{2}$$

From (2), it can be concluded that the pressure (psi), or wear, is proportional to the normal force applied and inversely proportional to the contact area (ft^2).

The larger the contact area the smaller the pressure. Vice versa, the smaller the area the greater the pressure.

In the case of continuous rod, the contact area is spread over the entire length of the string as opposed to the small surface area of the coupling every 25 feet in a conventional sucker rod string. Therefore, the resulting pressure is significantly less.

The area in contact with the tubing depends on the contact angle between the tubing and the rod or rod coupling. This angle is dependent on the radius of the rod and tubing used. It is somewhat difficult to estimate but without loss of generality an angle of 20° can be used for continuous rods and a bigger angle of 30° can be used for couplings in conventional rods, see Figure 4. It is important to note that the contact angle will increase over time as the rod or coupling digs into the tubing and the contact angle is only meant as an initial state angle.

The contact area is calculated as the length of the area times the arc length of contact, s, as in:

$$A_C = L_C \cdot s = L_C \cdot 2\pi r \cdot \left(\frac{\theta}{360}\right), \tag{3}$$

Where A_C is the area of contact (ft^2), L_C is the length of the contact area (ft), r is the radius of either the continuous rod or the coupling (ft), and θ is the contact angle between either the continuous rod and the tubing or the coupling and the tubing (degrees).

Using the equations above, the normal force and resulting pressure can be calculated for a segment of a 25 ft continuous rod versus conventional rod string at an inclination of 15 degrees with a specific fluid gravity of 1 and the weight/ft of 1-inch continuous rod and conventional rod. Results using equations (1), (2) and (3) are presented in Table 2.

Contact length for a conventional rod string is equal to the length of a coupling which is 0.33 ft, while the length of contact for the continuous rod is equal to 25ft. Due to the lighter rod string, the weight of the continuous rod string is 66.75lbs with a resulting normal force of 15.08lbf, while the weight of the conventional rod string is 72.8lbs with a resulting normal force of 16.45lbf.

The contact area for the continuous rod is 0.3635 ft^2 compared to the contact area for the conventional rod, which is 23 times smaller with a value of 0.01574 ft^2.

From equation (2), the resulting pressure between a conventional sucker rod and tubing is 1045.1 lb/ft^2 compared to 41.48 lb/ft^2 between continuous rod and tubing. The pressure between the continuous rod string and tubing string is 25 times less than the pressure between the conventional rod string and tubing string.

Using the results presented in Table 2, it can be concluded that using continuous rod greatly reduces the pressure and wear by increasing the contact area between the rod and the tubing. In the above scenario, the pressure was reduced by 96%.

Dogleg Severity and Side Loading:

Contact force is typically described as side loading in rod lift applications. Side loading is expressed by the following equation and is traditionally presented in pounds per 25-foot section of rod as a typical rod segment is 25 feet in length.

As can be shown in Table 2, because the side load and the resulting contact force are directly proportional to the weight of the rod string, side load and force values will be less for continuous rod than for a conventional rod.

Deviation surveys are used to assess the deviation of the well trajectory. Inclination, azimuth, and measured depth measurements are taken at regularly spaced footages. When the three-dimensional trajectory changes rapidly this produces a dogleg. Dogleg severity is a measure of the rate of change of the wellbore direction and is calculated with the following equation:

$$DLS = 100 \cdot \frac{\cos^{-1}(\cos\alpha_1 \cdot \cos\alpha_2 + \sin\alpha_1 \cdot \sin\alpha_2 \cdot \cos(\mu_2 - \mu_1))}{MD_2 - MD_1},$$

Where α denotes the inclination angle, μ denotes the azimuth angle and MD denotes the measured depth between two stations. Another important quantity to note is the side load. The side load is a representation of the intensity of the contact force at a particular depth. Side load is proportional to the peak polished rod load and relates to dogleg severity as seen by the following equation:

$$SL = PPRL \cdot \sin\frac{DLS}{4}.$$

Hence, side loads are proportional to rod load, therefore the lighter the load the smaller the associated side loads will be.

Flow Area and Elimination of Turbulent Flow:

Continuous rod provides a greater cross-sectional area for fluid flow. An advantage to continuous rod is a slight increase in production as the clearance between the tubing and the rod is increased. This results in unrestricted flow through a larger area.

Additionally, the absence of couplings in continuous rod eradicates the creation of turbulent flow. When dealing with low viscosity fluids, in parts of the rod string where the rod velocity is the largest, turbulent flow is induced, see [6]. The turbulent flow is created from both the couplings or the molded rod guides distributed along the rod string.

Turbulent flow can create crevice corrosion around the end of a rod guide or coupling in the form of small pits. The small pits can continue to propagate and result in a fatigue failure from erosion-corrosion due to the difference in diameter and therefore difference in flow imposed by the couplings or rod guides, cf. [2].

CONTINUOUS ROD REDUCES CAPEX AND OPEX

The cost of a continuous rod is slightly more expensive than a conventional rod. However, as discussed previously, in the case of deviation, which is predominant in a lot of wells today, a conventional rod string on bare tubing is insufficient to deal with the deviation and related wear alone. Therefore, it is common practice to add rod guides to the rod string. The rod guides are fixed on the outside of the rod string at different length intervals. The purpose of the rod guide is to absorb the contact between the rod and the tubing in highly deviated sections of the well. It is common practice to add between 4 to 6 guides per rod in a deviated section, greatly increasing the cost of a conventional rod string. A guided conventional sucker rod string will be similarly or more expensively priced than a continuous rod string. However, rod guides increase the friction in the well, increasing loading on the rod string and at surface.

Other improvements brought by continuous rod include the elimination of the rod fall problem, which means increased pumping speed and larger rod size may be used in the same tubing size, (or smaller tubing size), see [11].

Continuous rod strings are lighter than conventional rods and, as such, operators may be able to use a smaller pumping unit structure on a new installation. Each coupling on every 25-foot length of conventional rod adds a small amount of weight to the string. Since continuous rod has only two connections, one at the top and one at the bottom of the string, the same continuous rod string taper will be lighter than a similar conventional rod string. This is shown in Table 1. As mentioned above with the unrestricted flow area decreasing fluid friction and the distributed side loads decreasing mechanical friction, loads at the surface are reduced, see [10]. The coefficient of friction for continuous rod strings on bare tubing is significantly lower (generally 33%) than plastic guides on steel tubing. In severely deviated wells, it is not uncommon to use 6 to 8 rod guides per rod, greatly increasing the drag load.

Table 3 contains three examples, created using a predictive software, that illustrates advantages of continuous rod in comparison to conventional sucker rod.

For each case, target production was set at 225 bfpd with a water cut of 90%, and a pump intake pressure of 150PSI. The pump depth was set at 7,000 ft with an insert plunger size of 1.5 in and an efficiency of 80%. The rod string was composed of 2,225 feet of 1" rods, 4,475 feet of 7/8" rods followed by 300 feet of 1.5" sinker bar. The dogleg severity of these examples can be seen in Figure 8.

The three cases displayed in Table 3 are designed using a C912-305-168 pumping unit. The three cases are as followed: continuous rods with bare tubing, conventional sucker rods with bare tubing, and guided conventional sucker rods. The guided case is designed with four guides per rod.

As shown in Table 3, the continuous rod case has a PPRL of 28,775 lbs. yielding a pumping unit structure loading of 94%. The bare conventional rod case PPRL increases to 30,553 lbs. due to the couplings at every rod. This equates to pumping unit structure loading of 100%. Furthermore, the guided conventional rod case PPRL increases to 32,593 lbs. due to the added friction from the rod guides. This equates to pumping unit structure loading of 107%. It is not recommended to exceed a loading of 95% on the pumping unit structure so in both the bare conventional rod case and guided conventional rod case, a pumping unit with a larger structural rating is recommended.

Operators will have to use a pumping unit with a greater structure rating to decrease the structure loading to an acceptable value below 95%. The lighter continuous rod string and reduction in friction will reduce surface loads on the gearbox. As shown in Table 3, the GB loading with continuous rod case is 100%, bare conventional rod case is 105%, and guided conventional rod case is 117%. Additionally, due to the smaller load and friction with continuous rod, the decrease in predicted monthly electricity costs for this well is about $300 in savings / month when compared to the guided conventional rod case. This number has the potential to be higher because the gearbox in the first stroke is loaded at 117%. To get a more reasonable loading on the gearbox and increase the gearbox life (1), the design will need to be run with a smaller stroke length because stroke length usually has the largest effect on gearbox loading. This will require an increase in SPM to make the desired production rate and likely an increase in the monthly electricity cost. Also, this will cause more wear and tear on the downhole equipment due to the increase in cycles from the increase in SPM.

For wells that are on the threshold between two gearbox sizes, using continuous rod instead of guided conventional sucker rods may allow operators to purchase a smaller unit due to the reduction in loads. In many cases, continuous rod has the potential to reduce initial CAPEX costs on a new rod pump installation and reduce OPEX costs due to the lighter loads at surface and on the rods.

INSTALLING AND STORING CONTINUOUS ROD

Continuous rod requires a special piece of equipment known as a Truck mounted injector (TMX) for installation and pulling. A truck crane passes the injector to a conventional workover rig or Flush by unit. TMXs are equipped with hydraulics and controls to operate the injector and spool the rod in and out of the well.

During installation, the rod is spooled from a 6-meter reel through the guide arms into the injector and then into the wellbore. During a workover where the rod string must be pulled, the rod is pulled into the injector then through the guide arms before entering the collapsible service reel. See Figures 1, 2, 6, and 7.

Because continuous rod is spooled from a 6-meter reel, continuous rod can be kept in optimal condition until installed in a well, see Figure 5. The same, often, cannot be said for conventional rods which are often not stored properly.

CASE STUDY: CONVERSION FROM CONVENTIONAL SUCKER ROD TO CONTINUOUS ROD

In this case study, five high failure rate wells operating in the Wolfcamp field were converted from conventional sucker rods to continuous rod. These wells are producing from the Middle and Upper Wolfcamp formations and were experiencing problems with rod on tubing wear due to deviation.

A typical design for these wells would include a pump depth set between 5,000 to 6,000 ft with a 1.75" insert pump and C912-427-192 unit. At the time of conversion, production for these wells typically ranged from 200 to 350 bfpd. Figure 9 displays a typical graph of dogleg severity for one of these wells, with max dogleg severity ranging between 2-3 deg/100ft. As can be seen from Figure 9, there are multiple instances of dogleg severity greater or equal to 2.0 deg/100ft at varying depths throughout the wellbore including shallow depth of 1,100 ft, 1,800 ft, 2,800 ft and 3,100ft. According to [5], severe doglegs such as these in the shallow section of any well cause increased mechanical friction resulting in increased failures and operating costs.

Well No. 5 in this case study had a 1.75-inch insert pump set at 5,547 ft with a rod string taper consisting of 5,347 ft of .875-inch D41 rod and 200 ft of 1.5-inch sinker bars. This well had a C912-427-192 pumping unit. When Well No. 5 was converted from conventional sucker rods to continuous rod, the targeted production rate was 220 bfpd. The dogleg severity for this well can be seen in Figure 10. The shallow dogleg severity near 700 ft is one of the worst locations to have deviation as the rod loading near the top of the rod string is high. This results in a higher side load than the same dogleg severity at a deeper depth. Prior to continuous rod, this well experienced a failure rate of two holes in tubing per year. This well ran with continuous rod for 670 days before being converted to gas lift due to its high GOR but ran over 3 times the amount that conventional sucker rod ran. This example proves that through increased contact area, continuous rod reduces the pressure between the rod and the tubing string, reducing tubing failures.

FAILURE RATE REDUCTION

As can be seen in Table 4, all five wells in this case study except for Well No. 4 had a failure rate of 2.00 failures per year with conventional sucker rods.These failures were either caused by a hole in tubing or rod part. Well No. 4 had a failure rate of 1.00 prior to conversion to continuous rod. After conversion to continuous rod, there were no reported failures on these wells.

Prior to continuous rod, Well No. 1 experienced a failure rate of 2.00 failures per year. After installing continuous rod, the well ran for 907 days, or 2.48 years. Instead of computing a failure rate on wells that have never failed, the number of failures avoided by converting to continuous rod was calculated. The number of failures avoided was calcuated by multiplying the average total failure rate for each well by the failure free runtime in years. Since conversion to continuous rod, five failures were avoided for Well No. 1.

Well No. 2 has avoided an average of eight failures since conversion with a current runtime of 1585 days or 4.34 years while Well No. 3 avoided an average of five failures in 2.65 years. Well No. 4 avoided an average of two failures while Well No. 5 avoided an average of three failures.

The average number of failures avoided over these five wells is 4.6 failures during their runtime, as displayed in Table 5.

Wells No. 1, No. 3, No. 4, and No. 5 were later converted to gas lift due to their high GOR while Well No. 2 is still running today.

Triple Crown's average repair cost for a tubing leak on these wells is $41,500. Their average repair cost of a rod part is $35,000 as displayed in Table 6. As can also be seen from Table 6, there is an initial cost difference of $8,000 when installing a continuous rod string compared to a conventional rod string for these particular wells. However, when multiplying the average number of avoided failures by the respective average repair costs for both tubing leaks and rod parts, the incurred savings is $161,000 for rod parts and $190,900 for tubing leaks.

This means that for a $8,000 increase in up front investment in continuous rod, this operator was able to save on average $161,000 to $190,900 of repair costs per well.

Based on the above failure rate reductions, Triple Crown Resources began converting similar wells that met their criteria from ESP to rod lift with continuous rod instead of conventional sucker rod.

CONCLUSIONS

The use of continuous rod reduces wear and failures by eliminating couplings and removing the need for rod guides. Continuous rod distributes side loading over a larger contact area, reducing the stress seen on the rods and tubing strings. The connectionless aspect of the continuous rod also reduces friction through the elimination of turbulent flow. The lighter continuous rod reduces side loads and can also increase savings through lower loadings on the rod string as well as at surface. Lastly, by reducing the pressure between the rod and tubing strings, continuous rod can significantly reduce failure rates as seen in the above case study.

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ACKNOWLEDGEMENTS

Special thanks to the Triple Crown for their cooperation and sponsorship and Lightning Production Services' Team.

1000 FT					
	Conventional Rod		Continuous Rod		Difference/1000ft
Diameter	lb/ft	1000 ft (lbs.)	lb/ft	1000 ft (lbs.)	lbs.
3/4 “	1.634	1,634	1.49	1,490	144
7/8”	2.224	2,224	2.04	2,040	184
1 “	2.912	2,912	2.67	2,670	242
1-1/8 “	3.676	3,676	3.38	3,380	296
7000 FT 87 TAPER					
	Footage	Conventional Rod		Continuous Rod	
Diameter	ft	lb/ft	lbs.	lb/ft	lbs.
1 “	2,300	2.912	6,698	2.67	6,141
7/8 “	4,400	2.224	9,786	2.04	8,976
1.5 “SB	300	6	1,800	6	1,800
		TOTAL	18,283	TOTAL	16,917

Table 1: Weight Comparison of Continuous Rod and conventional rod for 1000ft and 7000ft taper

Type	$L_{Contact}$ (ft)	W_r (lbs)	S (in)	$A_{Contact}$ (ft^2)	F_N (lbf)	σ (psi)
Conventional	0.33 ft	72.8	0.0477	0.01574	16.45	1045.1
Continuous Rod	25 ft	66.75	0.01454	0.3635	15.08	41.48

Table 2: Stress applied to a 25 ft segment of 1” Rod

Pumping Unit	SL	Rod String	PPRL	MPRL	Loading	GB Torque	GB Loading	Kw/day	Monthly Electricity
C912-305-168	168	Continuous Rod	28,775	9,468	**94%**	914	100%	775	$1,419
	168	Conventional Rod	30,553	10,457	**100%**	954	105%	807	$1,476
	168	Guided Conventional	32,593	9,808	**107%**	1065	117%	931	$1,854

Table 3: Pumping Unit Loading Comparison

WELL	ROD FAILURE RATE	TUBING FAILURE RATE	TOTAL FAILURE RATE
WELL NO. 1	1.00	1.00	2.00
WELL NO. 2	2.00	0.00	2.00
WELL NO. 3	1.00	1.00	2.00
WELL NO. 4	1.00	0.00	1.00
WELL NO. 5	0.00	2.00	2.00

Table 4: Triple Crown Case Study Failure Rate on Conventional Sucker Rods

WELL	DAYS IN OPERATION	YEARS IN OPERATION	NO. OF ROD FAILURES	NO. OF TUBING FAILURES	FAILURES AVOIDED
WELL NO. 1	907	2.48	0.00	0.00	5
WELL NO. 2	1585	4.34	0.00	0.00	8
WELL NO. 3	968	2.65	0.00	0.00	5
WELL NO. 4	765	2.09	0.00	0.00	2
WELL NO. 5	670	1.83	0.00	0.00	3
AVERAGE					4.6

Table 5: Triple Crown Case Study Runtimes and Avoided Failures Since Conversion to Continuous Rod

FAILURE TYPE	AVG. FAILURES AVOIDED	AVG REPAIR COST/WELL	COST SAVINGS	INITIAL EQUIP COST CONVENTIONAL	INITIAL EQUIP COST CR	TOTAL INITIAL COST DIFF
TUBING	4.6	$41,500	$190,900	$24,000	$24,000	$0
ROD	4.6	$35,000	$161,000	$18,000	$26,000	$8,000

Table 6: Case Study Average Savings per Well After Conversion to Continuous Rod

Figure 1: Spooling rig for continuous rod installation

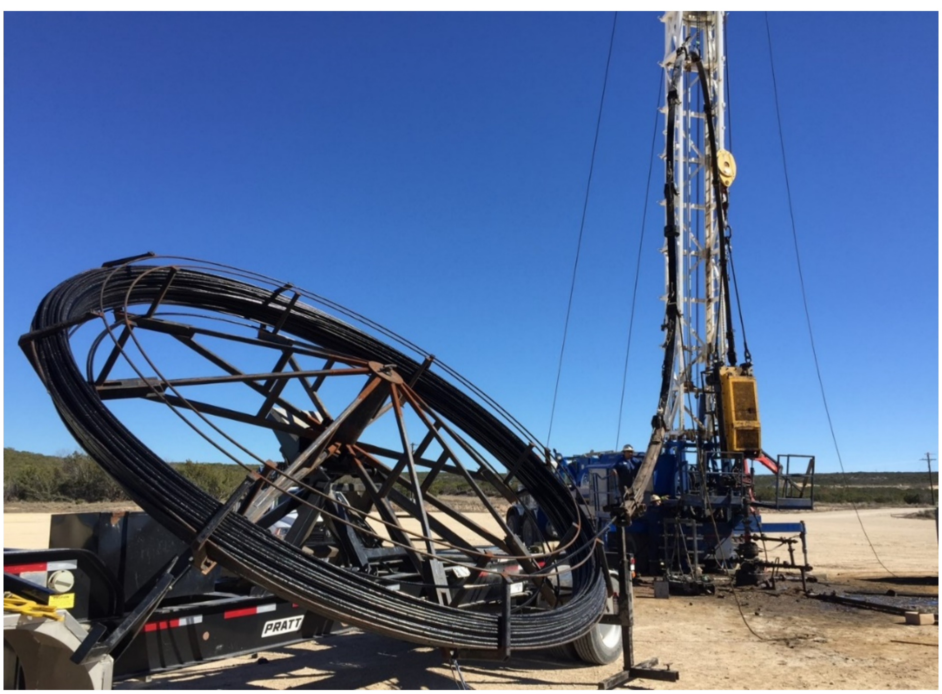

Figure 2: Spooling rig for continuous rod installation – close up

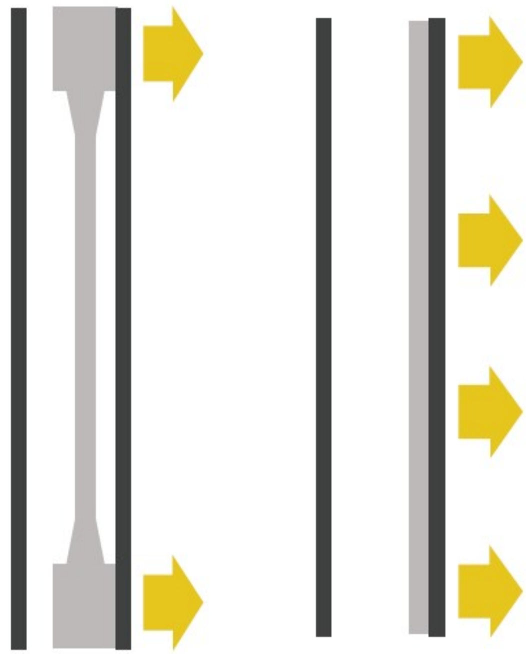

Figure 3: Pressure exerted on tubing from conventional rod compared to continuous rod.

Figure 4: Difference in flow area of conventional rod string with couplings and continuous rod

Figure 5: Double reel transport trailer rig for continuous rod installation – close up

Figure 6: TMX & RSU

Figure 7: Service Collapsible Reel for Workover Job

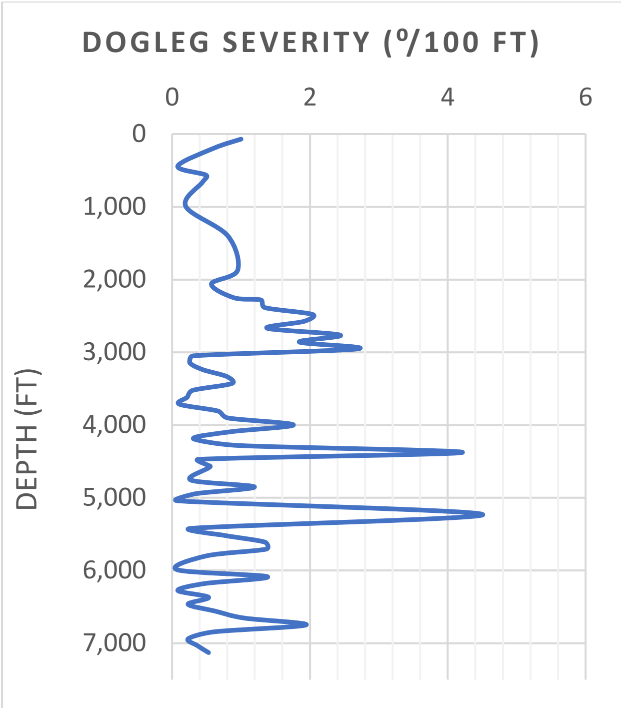

Figure 8: Dogleg Severity for Example Cases

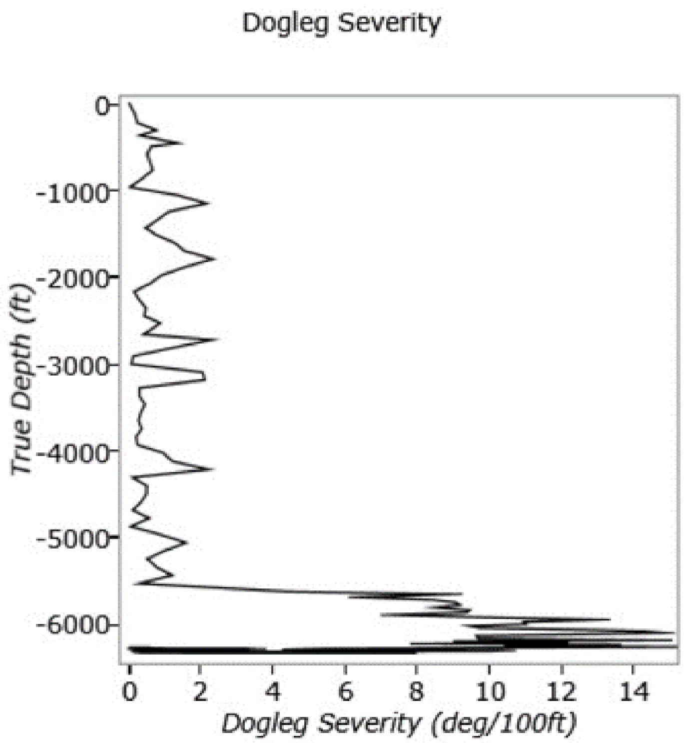

Figure 9: Typical dogleg severity plot for Case Study

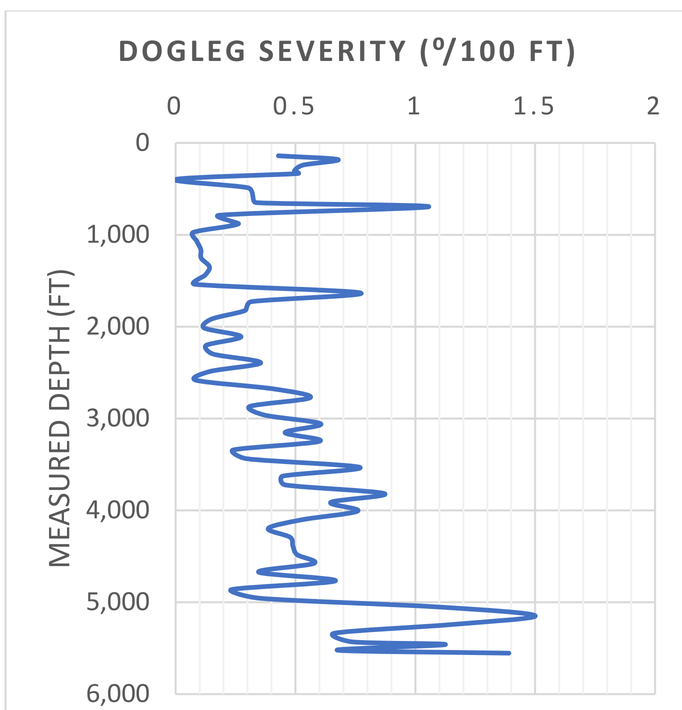

Figure 10: Dogleg Severity for Well No.5