CORROSION AND WEAR PROTECTION IN ENDLESS ROD DESIGNS IN UNCONVENTIONAL WELLS FEATURING KEBOND TECHNOLOGY – POLYKETONE-BASED EXTRUDED COATING

Courtney Richardson
Occidental

Taylor Krenek
Lifting Solutions

ABSTRACT

One of the challenges associated with continuous rod arises from corrosion related to the inhibitor film potentially being wiped away from rod-on-tubing contact (“inhibitor wipe”). This can lead to inadequate protection, allowing corrosion to develop, resulting in stress risers on the rod surface that, under cyclic loading, can lead to cracks that can propagate across the rod body until there is insufficient cross section to sustain the load, causing it to fail. This paper presents performance data highlighting axial load reductions, runtime improvements, and other successes using Lifting Solutions’ KeBond-coated Endless Rod technology in reciprocating rod pump (RRP) applications.

BRIEF HISTORY OF CONTINUOUS ROD

Originally conceptualized and patented in Canada by Alex Palynchuk in the late 1960s, continuous rod is just that, a continuous rod body with two threaded connections (“pin ends”), top and bottom, whether it is in a 1,600 ft or 13,500 ft well. Initially developed for reciprocating rod pumping (RRP) applications in light oil, continuous rod use expanded over time into RRP heavy oil slant wells, both cold flow and thermal. Over the years, advancements in servicing equipment, welding methodologies, and metallurgies have opened the operating envelope significantly for continuous rod. The primary benefits over conventional sucker rods originate from the significant reduction in couplings/connections which, on average, account for more than 50% of failures. By eliminating up to 99% of the couplings found in a typical conventional string, continuous rod reduces side and drag forces by distributing contact loads throughout the tubing string rather than concentrating them on couplings or rod guides. This also allows for an 8 to 12% reduction in the overall string weight, thereby reducing surface equipment loading. In the US, continuous rod is typically deployed in deeper, deviated wells with higher side loads and dogleg severity, though other applications are becoming more prevalent, such as slimhole applications where tubing size is limited and when pumping in the curve.

HISTORICAL CHALLENGES ASSOCIATED WITH CONTINUOUS ROD

Over the last several decades, continuous rod has faced three main challenges: welding, service quality and availability, and corrosion. Welding challenges stemmed from now-outdated electrical resistance flash-butt methods that applied high current to melt the rod ends which were then forged together. This method was inconsistent in nature and could trap oxides and cast metal in the forged ends, leading to premature failure. In 2004, the oxy-acetylene forged butt weld process was introduced to the market and is now the most common method, enabling consistent and reliable welds that can withstand operational loads (Figure 1).

Figure 1a

Figure 1b

Figure 1: Example of oxy-acetylene forged butt weld in process (1a) and final product (1b).

The initial lack of installation and servicing capabilities hindered the adoption and growth of continuous rod early on. A high well count was necessary to justify the investment by the service companies in the specialized equipment, training, and servicing infrastructure required to install continuous rod, which made it difficult initially to establish a foothold in new markets. Until recently, few service providers outside Canada made this investment in continuous rod service fleets and maintenance programs. Now, these services are offered in the Permian and Bakken, which has allowed the use of continuous rod to further expand.

With welding and service concerns mitigated, corrosion becomes the highest priority. In many cases, corrosion prevention is very difficult. Continuous rod is typically deployed in deviated wells where rod-on-tubing contact is inevitable. Even with some of the best rod rotators on the market and expensive, robust chemical programs, inhibitor wipe will lead to corrosion fatigue, resulting in failure. After the success of its first-generation barrier-coated continuous rod, which was installed in over 4,000 wells, the vendor began deploying the next generation of coating on its continuous rods across Canada and the US in 2023, to combat corrosion fatigue failures that challenge operators daily.

THE NEXT GENERATION OF COATED CONTINUOUS ROD

The second generation of coated continuous rod by this vendor is comprised of an engineered, blended thermoplastic polyketone outer coating fused to a tie layer bonded to the rod body. Its primary objective is to serve as a barrier, protecting the parent steel material from wellbore fluids and from mechanical damage.

After the rod surface is conditioned, a bonding agent is applied to the rod body before passing it through two extrusion heads. The patented process extrudes the tie layer and then the final outer polyketone layer, bonding the thermoplastic polyketone to the steel.

Figure 2. Cutaway diagram of coated continuous rod

A key feature of this product is the relatively thick coating, as shown in Figure 2, which extends runtimes by reducing rod-on-tubing wear, especially when compared to thinner coatings also explored during product development. Additionally, the outer coating reduces the coefficient of friction throughout the rod string, improves the downhole stroke, decreases the peak polished rod load, and increases the minimum polished rod load.

As with any downhole coated component, certain mechanical and service limitations apply to this product. The current generation of coated continuous rod requires a tie layer to bond the polyketone to the rod body. This multilayer coating has a maximum downhole operating temperature of 180°F. Polyketone has an industry-adopted limit of 230°F. (Future generations of coated continuous rod will be engineered to meet or exceed this limit.) Specialized gripper pads prevent damage to the coating during servicing, which could cause premature failure. These pads have a maximum string weight limit of 22,000 lb and are typically designed to approximately 8,500 ft.

Polyketone can be applied by extrusion to the current rod grade offerings specified in the chart in Figure 3 below. Please note: all mechanical and chemical properties of the base rod grade still apply, in addition to the polyketone limitations discussed previously.

Rod Grade	Material Code	Materials	Min. Tensile Strenth (ksi)	Min. Yield Strength (ksi)	Max Average Hardness (HRC)
D	C-Mn	Carbon Alloy	115	85	28
ND	Ni-Cr-Mo	Nickel - Chrome - Moly	115	90	28
NS	Ni-Cr-Mo	Nickel - Chrome - Moly	140	115	36

Rod Grade	3/4"		7/8"		1"		1 1/8"		1 3/16"	
	Torque (ft*lb)	Rig Pull (lbs)	Torque (ft*lb)	Rig Pull (lbs)	Torque (ft*lb)	Rig Pull (lbs)	Torque (ft*lb)	Rig Pull (lbs)	Torque (ft*lb)	Rig Pull (lbs)
D	410	33,721	650	47,209	975	60,698	1,390	76,435	1,630	85,427
ND	430	35,969	690	49,458	1,030	65,194	1,470	80,931	1,730	89,923
NS	550	47,209	890	62,946	1,330	83,179	1,890	103,412	2,220	114,653

Figure 3: Coated continuous rod grade mechanical properties.

AN UNCONVENTIONAL CASE STUDY IN THE PERMIAN

The vendor partnered with this operator on a pilot project involving ten unconventional wells on reciprocating rod pumps (RRPs) where its polyketone-coated continuous rod was installed to increase mean time between failures.

Prior to the pilot, the operator and vendor collaborated extensively on the trial protocol and developed specific well candidate criteria. The criteria included wells with:

- A proven history of failures due to corrosion fatigue, supported by failure analysis, where the corrosive agent may be CO_2, H_2S, bacteria, or a combination thereof.
- At least two failures in the last six months.
- High concentrations of CO_2, H_2S, or a combination thereof.
- High water cut (with or without chemical treatment in place).
- A functioning low-speed, high-torque-rated rod rotator, with only one-way style (not ratchet-style) bearings.

- Not more than 22,000 lb of string weight (8,500 ft or less) and not exceeding 180°F in BHT.

The operator installed the test strings in wells meeting the established criteria and, per the protocol, generated a target runtime as a preliminary performance metric. The metric was calculated by averaging the previous two runtimes between failures and then multiplying by two. This metric primarily assesses the product's economic value, considering the increased costs and evaluating the return on investment (ROI).

Additional factors were considered when selecting candidate wells to ensure quantifiable improvements in axial loads, such as making sure that no wells would see drastic changes in SPM (strokes per minute) or SL (stroke length). From a design standpoint, the operator preferred wells with minimal changes in displacement, as any configuration changes could impact the ability to quantify performance metrics related to friction reduction and load improvements. In the case study, any wells with potential configuration changes impacting performance during the trial are transparently disclosed.

Axial Load Reductions

The operator meticulously monitored the average peak and minimum polished rod load trends across the ten trial wells where full-length polyketone rod strings were installed. An anticipated benefit of polyketone, second to corrosion protection, was a reduction in friction coefficient, prompting close analysis of the peak and minimum polished rod loads. An increase in the minimum polished rod load was observed in six of the ten wells, while a decrease in the maximum polished rod load was noted in eight wells. These results indicate that the majority of polyketone applications demonstrated axial load improvements, signifying a friction reduction in these highly deviated wells.

A significant reduction in peak loads was particularly evident in Well No. 7, accompanied by a noticeable reduction in the minimum polished rod load. It is important to note that Well No. 7 underwent a pump diameter reduction from 2 in. to 1.75 in. during the installation, which likely accounts for the trend observed in loading changes. For six of the ten trial wells, the variance in strokes per minute (SPM) during operation did not exceed 0.7 SPM, with the largest variance across the entire ten-well subset being 1.8 SPM (Figure 4).

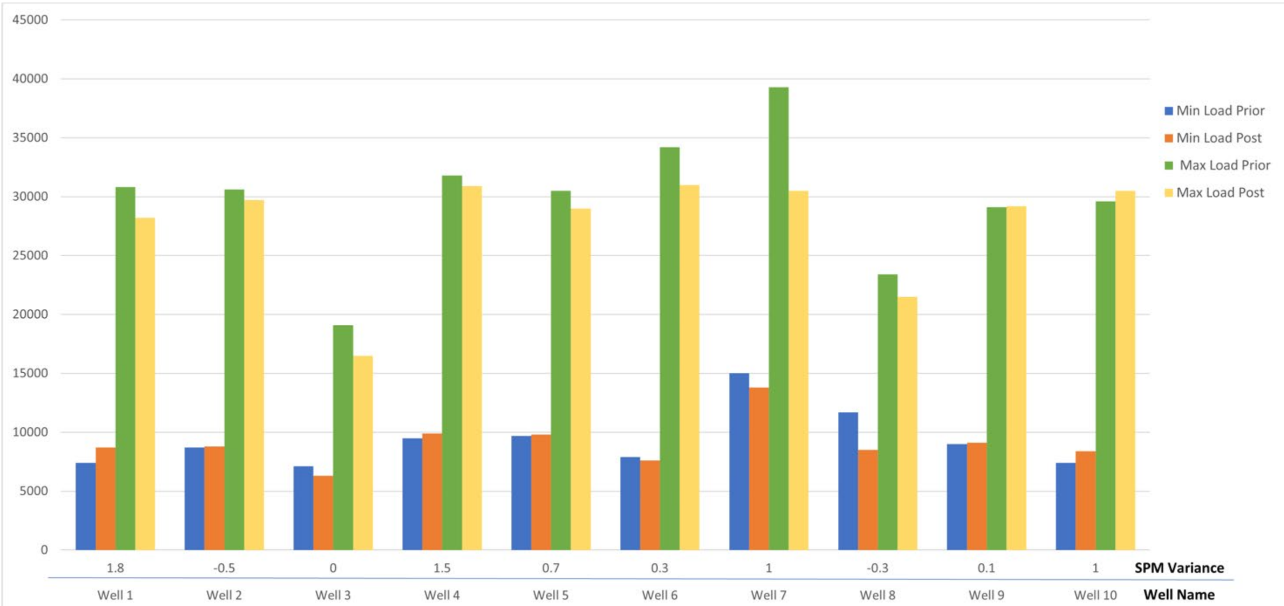

Figure 4. Load trends and SPM variances.

Runtime Improvements

During assessment of the candidate wells, the operator used the preliminary performance metric per the protocol (the average runtime between failures of the last two instances times two) as the target runtime for the polyketone implementation. Notably, five of the ten wells exceeded their target runtimes with the polyketone strings. Four of these five wells continue to accrue runtime on the original polyketone installations. Furthermore, nine of the ten polyketone strings initially installed remain operational, with the exception of Well No. 6 (highlighted in the purple box in Figure 5). A detailed look at Well No. 6 and observations on the equipment pulled are described in greater detail below.

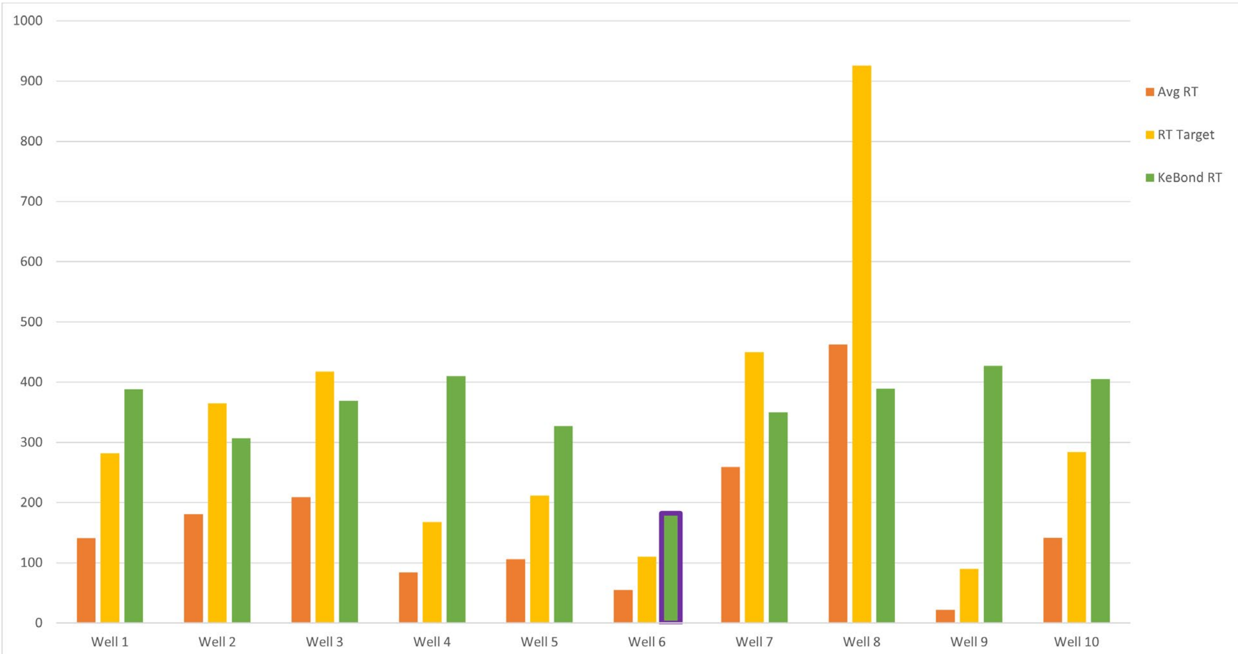

Figure 5. Runtime trends (previous average, target runtime, polyketone runtime).

Well No. 6 Case Study

Well No. 6 ceased accruing runtime when it experienced a failure at 182 days due to severe wear on a rod part. This resulted in the replacement of the polyketone string, as the previous runtimes between failures were 13 and 98 days, respectively. Inspection revealed that the polyketone string suffered extensive wear through to the steel rod beneath the coating below 4,000 ft, a highly loaded area. Such severe unilateral wear suggested that, despite the operational use of a rotator, torque energy was being stored and subsequently released, resulting in unilateral wear below the most severe inclination and dogleg severity. Additionally, the polyketone coating had separated from the steel rod parent material during retrieval, further emphasizing the inadequate rotation from the surface with the operationally verified rotator.

Well No. 6 has a history of short runtimes between failures, attributed to side loading throughout the wellbore. As illustrated in Figure 6, Well No. 6 experiences significant side loading within the initial 400 ft and continues to encounter side loads exceeding 150 lb in two other intervals in the wellbore. Furthermore, this well exhibits high corrosivity and has a corrosion-related failure history, requiring continuous treatment. The runtime improvement observed with polyketone was considered a success, given the historical frequency of failures and considering the wellbore trajectory, corrosive fluid properties, and the throughput of 300 barrels of total fluid per day.

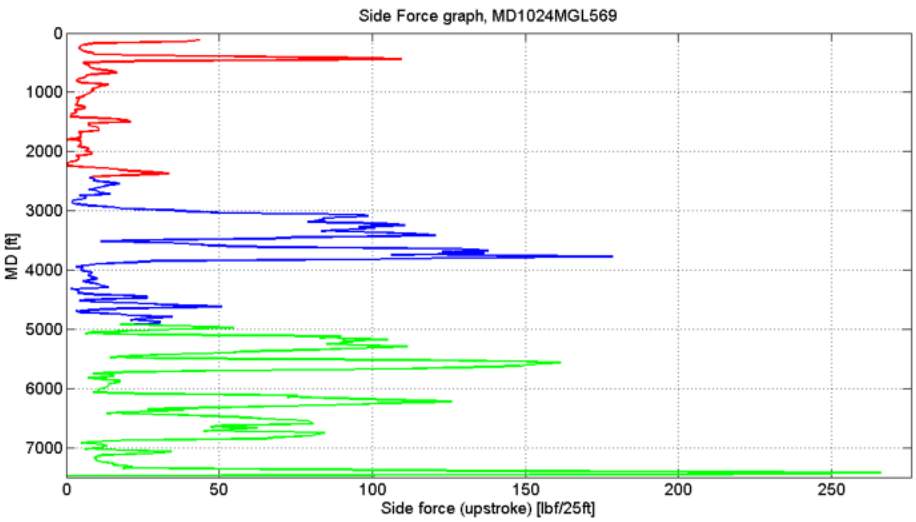

Figure 6: Well No. 6 side loads.

Detailed Case Study Results

A comprehensive analysis of two wells within the Unconventional Permian Case Study shows the performance metrics of Well No. 4 and Well No. 9. These wells, completed in the Midland Basin, are subjected to pronounced gas slugging. Both wells typically operate with variable pump fillage rates ranging from 50% to 95%, regardless of the bottomhole assembly gas separation configurations. The challenging operational environment in these wells significantly impacts the frequency of failures, thus presenting an additional layer of complexity in maintaining low failure rates.

Well No. 4 Case Study

Well No. 4 was converted to an RRP after being on an electric submersible pump (ESP) in late 2023. Shortly after conversion, the well experienced two brief runs on the RRP, with failures primarily driven by corrosive fluids causing corrosion fatigue failure due to corrosion fatigue by inhibitor wipe. These run intervals were 69 and 63 days, respectively. From an operational standpoint, the well was running with a 2-in. pump, 186 in. SL, and 3-5 SPM on a variable speed drive (VSD). The pump was set at 6,850 ft, approximately 150 ft above KOP. The well has several areas experiencing up to 150 lb of side loading; however, starting at around 6,250 ft, side loads in this well increase to over 500 lb (Figure 7). Given the side loading and the corrosive fluids properties, the operator determined that the best chance for success was with polyketone-coated continuous rod.

This well continues to operate with polyketone-coated continuous rod without any subsequent failures. The run days for the life of the well are outlined in the chart below

(Figure 8). Currently, polyketone run days are at 411 days and still accruing, approaching a runtime similar to historical ESP run days between failure.

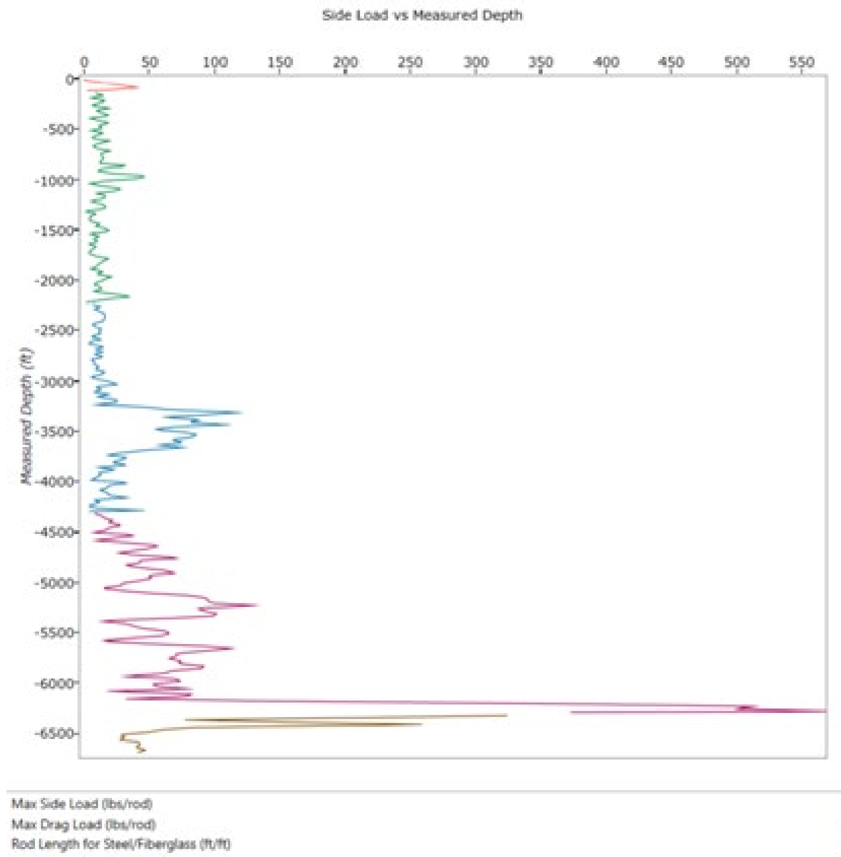

Figure 7: Well No. 4 side loads.

	Install Number	MOP	Install Date	Start Date	Stop Date	Run Days
	1	ESP	13 May 2020	19 May 2020	18 Oct 2021	517
	2	ESP	10 Nov 2021	12 Nov 2021	31 May 2023	565
	3	RODPUMP	22 Jun 2023	22 Jun 2023	30 Aug 2023	69
	4	RODPUMP	22 Sep 2023	26 Sep 2023	28 Nov 2023	63
	5	RODPUMP	04 Jan 2024	04 Jan 2024		411

Figure 8: Well No. 4 Run Days Between Failure

Well No. 9 Case Study

Well No. 9 was also converted to an RRP after being on ESP in late 2023. Shortly after conversion, the well experienced two brief runs on the RRP. One RRP failed due to trash in the pump and the other failure was driven by corrosive fluids causing corrosion fatigue failure due to mechanical corrosion by inhibitor wipe. These run intervals were 6 and 37 days, respectively. From an operational standpoint, the well was running with a 2 in. pump, 216 in. SL, and 3.5-6 SPM on a VSD. The pump was set at 6,905 ft, approximately 380 ft above the kickoff point (KOP).

This well continues to operate with polyketone-coated continuous rod without any subsequent failures. This well sees up to 260 lb of side load in the first 1,200 ft of the wellbore, which creates a unique challenge with rod pumping (Figure 9). High shallow side load in the wellbore paired with a rod rotator has not proven to evenly distribute wear. From the operator's experience, the higher and shallower the side load, the less reliable the rotator is for wear distribution. The run days for the life of the well are outlined in the chart below (Figure 10). Currently, polyketone run days are at 424 days and still accruing, approaching similar runtime to historical ESP run days between failure.

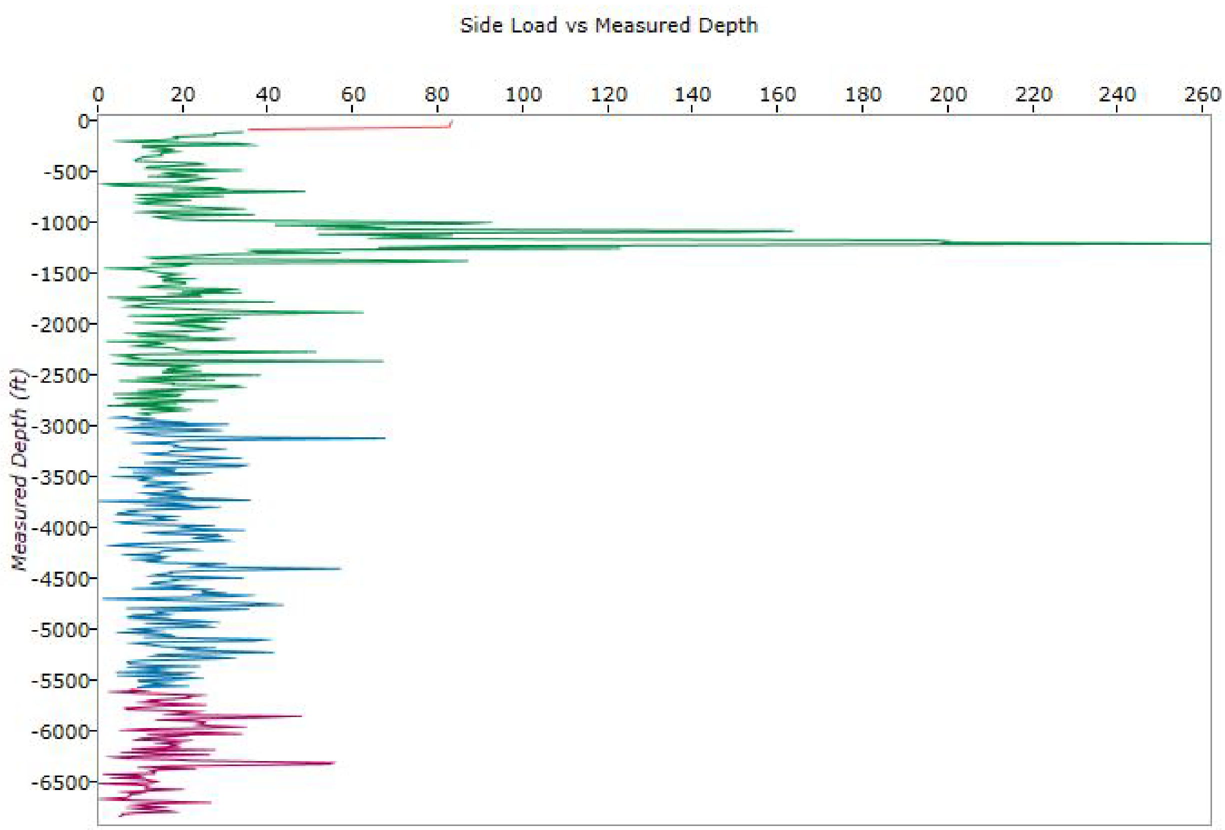

Figure 9: Well No. 9 side loads.

Install Number	MOP	Install Date	Start Date	Stop Date	Run Days
1	ESP	06 Apr 2021	10 Apr 2021	09 Jun 2022	425
2	ESP	13 Jun 2022	13 Jun 2022	28 Aug 2023	441
3	RODPUMP	10 Oct 2023	10 Oct 2023	16 Oct 2023	6
4	RODPUMP	01 Nov 2023	01 Nov 2023	08 Dec 2023	37
5	RODPUMP	18 Dec 2023	19 Dec 2023		424

Figure 10: Well No. 9 run days between failure.

CONCLUSIONS

After the trials were completed, the operator validated KeBond-coated Endless Rod as an effective solution for extending the wear life on rod and tubing, mitigating inhibitor wipe corrosion, and reducing axial loads. Based on the trial outcomes, the operator's application strategy for polyketone focuses on wells with a documented history of corrosion fatigue failures. These failures may be due to corrosion agents such as CO_2, H_2S, bacteria, or a combination thereof. Additionally, polyketone-coated continuous rod is intended for initial rod lift conversions in wells where side loads pose significant challenges to conventional rods, particularly in those experiencing side loads exceeding 150 lb within the first 1,500 ft of the wellbore.

The operator plans to deploy this product in enhanced oil recovery (EOR) wells that are less than 5,500 ft deep and characterized by highly corrosive fluids. These wells often use older and smaller pumping units. The continuous rod reduces the number of connections, lowers the overall weight, and offers corrosion protection, making it ideal for smaller pumping units. This weight reduction is critical for ensuring the structural integrity of these units.

To date, the operator has installed 159,000 ft of polyketone-coated continuous rod in 22 Permian Basin wells and continues to see reduced failure frequencies with these applications. The vendor is developing new generations of coatings to enhance the performance of its coated continuous rod, with the goal of extending operational capabilities into deeper and hotter well conditions beyond the current limitations of polyketone.