OPTIMIZING THE LIFECYCLE OF PERMIAN WELLS

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Liberty Lift

ABSTRACT

As an operator, success rests in trying to maximize safety and production while minimizing your cost and downtime. Most operators choose ESP as a first form of lift and will later transition to gas lift, rod pumps, jet lift, etc. Other operators choose to use gas lift or rod lift as a first form of lift.

Each of these forms of lift presents its own rewards and drawbacks.

For example, overtime, ESP can become oversized for the production requirement of the well. At that point, it can become more economical to install gas lift, rather than resize the ESP pump. Solids, Deviation and corrosive environments are inhibitors for ESPs and rod lift limiting the production potential for the operator.

In other applications, long stroke units or conventional rod pumping offer the best solution with high production rates at a much lower cost than an ESP installation.

In this paper, benefits and challenges for each ESP, Gas Lift and Rod Lift and insights on the best conversion time, will be discussed.

This paper aims to provide data to help the customers understand how employing the best type of lift at the most appropriate time directly translates to maximizing revenue and production while minimizing losses and failures.

INTRODUCTION

The way operators in the oil and gas sector assess artificial lift techniques for producing wells has changed significantly because of the emergence of unconventional resources. Unconventional resources have long deep undulating laterals, which can create zones with different properties in terms of porosity and permeability. Unconventional wells are characterized by steep declining production rates and unpredictability and abundance of gas and solids.
This is particularly true for the various hydrocarbon-producing zones in the Delaware and Permian basins. In addition to having unique traits, these unconventional zones can have complex borehole geometries, necessitating the use of specialized techniques to maximize recovery and optimize production.

Planning the lifecycle of an artificial lift well in these reservoirs is challenging.
While those wells can initially produce generous volumes of fluids, this initial flow is short lived, see [2]. When the reservoir pressure is too low for the well to naturally bring water and oil to the surface, artificial lift is used. As a result, in addition to a thorough comprehension of the well's unique production characteristics, artificial lift solutions also call for a customized approach to several important elements. Wellbore configuration, solids and corrosion, pressures and temperatures, scalability, infrastructure, cost and economics, and dependable run times are a few of these variables.

Deviation in the wellbore configuration can negatively impact most artificial lift systems and should be evaluated when determining lift type. Severely deviated wells can create difficulties installing the long BHAs of ESPs and rod pumps.
For ESPs, deviation can cause damage to the cable when running the installation in hole with a workover rig, whereas in the case of rod pumps, deviation can cause rods/couplings or the pump to rub against the tubing when reciprocating up and down for pump action. Even though some techniques are available to minimize or mitigate damage, such as clamps to prevent the cable from rubbing against the casing walls and rod guides to centralize the rod string inside the production tubing, these solutions only delay failures.

Solids and corrosion can cause significant wear and tear on equipment. This can result in potential failure in systems like sucker rod pumps, ESPs, and gas lift. Some of these issues can be mitigated with chemical treatment programs to extend the run life of the lift type and must be considered as part of the artificial lift strategy of a well.

Scalability of the system to meet the different phases of decline in the life of the well needs to be considered. Each artificial lift type has its own useful life, when it comes to producing wells. Even though the useful life of some of these lift types can overlap, the ability of these systems to continue to effectively produce throughout changing reservoir conditions without a costly design change, can differ considerably.

Artificial Lift systems can have very different infrastructure requirements. Power availability, power lines, sub-stations, transformers, HP injection gas, gas pipelines, gas treatment systems, compression, and facilities can be challenging to plan, acquire, and buildout. Electricity is provided by multiple co-ops, which can make requests like upgrades to the power grid or long overhead powerline runs difficult
Natural gas for injection also needs consideration and planning. Determining the source of the injection gas, securing a buyback agreement if needed, acquiring compression to reach required operating pressure, and easements required to run suction and injection lines to assets must all be considered as a part of the artificial lift strategy.

Cost and economic considerations are likely a primary focus when planning a production strategy. Purchase and new installation capital costs, R&M costs, operational costs, and replacement capital, can vary notably from one form of lift to another. The same lift type can also vary in costs from region to region. Vertical depth, electricity costs, infrastructure requirements, required skilled personnel, corrosion and/or solids, and many other factors can impact real costs of artificial lift.

To maximize both performance and cost-effectiveness, runtime considerations are crucial when creating an artificial lift strategy. Some key determinants are system efficiency, power consumption, and equipment longevity. Key parameters like temperature, pressure, and flow rates must be continuously monitored to identify any early indications of wear or malfunction that could lower runtime efficiency leading to costly maintenance and component replacements.
Operators assess these crucial parameters to optimize a well's artificial lift strategy and identify when a change in lift type is necessary. To address most of the goals of operators developing unconventional resources in the Delaware and Permian Basins, a few types of artificial lift systems have become the preferred. This paper focuses on gas lift and rod lift as primary and secondary lift types and explains the specific selection criteria that make these lift systems the obvious choice for the Delaware and Permian basins.

ESP

Many land-based operators, particularly those in the Permian basin, rely on a strategy of boosting early life well production to yield the maximum rate of return, cf. [2]. Electric submersible pumps (ESPs) have become a go-to method of artificial lift for achieving high fluid production volumes with generally acceptable run times and overall efficiency. The operating range of ESPs has dramatically increased by using variable frequency drives (VFDs), advanced impeller designs, rotary gas separators, and various other enhancements. However, rapidly declining rates of unconventional wells and numerous other factors often spell trouble for ESPs as can be seen in [5].

When selecting ESPs as a primary method as opposed to other available artificial lift options, particularly in horizontal wells, several factors must be considered, such as electricity requirements and well geometry.

The availability of electricity is a crucial factor. In the Permian, well sites are often extremely remote, and the infrastructure simply does not always exist to provide the high voltage necessary for ESP implementation at a cost that makes sense to the operator. As an alternative, on site power may be used, but it often proves to be a costly option as well.

Well geometry is another consideration. Wells characterized by extreme deviation or intense dog leg severity can prove to be problematic for ESP implementation. Considering the sheer size of ESPs and their associated control cables, use in challenging well bores can prove to be difficult and often leads to costly fishing operations for retrieval.

Naturally produced environmental factors within the wellbore is another aspect to carefully review. When Permian wells are flowed back post fracture, natural gas and highly abrasive sand are both produced results, cf. [1, 6, 13].

Overtime, as natural gas to liquid ratios (GLRs) increase, ESP performance can be dramatically inhibited when they are forced to operate outside of their acceptable range thresholds. As gas is produced in large volumes, it can cause overheating conditions through gas locking. In a study performed by Baker Hughes, cf. [ZHENG], tests were conducted to determine the severity of the impact of gas locking on an ESP. Results showed that for every 2 hours of ESP operations during a gas locking event, the temperature would rise to an average of 430°F. High temperatures result in multiple failures throughout the ESP equipment including, but not limited to: unseated carbide bushings cutting the shaft, thermal shock and degraded carbide parts, and damaged motor lead extension (MLE). These failures decrease overall production, and it degrades the mechanical integrity of the pump. This leads to higher maintenance costs and eventually a costly ESP failure, which translates to more expenses for the operators to replace the expensive pump.

As sand is produced, it can damage and erode internal pump parts and impellers as it is agitated and collects within tight internal tolerances. Although screens can be utilized to mitigate the solids, this requires intervention and maintenance, which yields higher overall intervention and operating costs for the operator. Bottom hole assembly can be used to mitigate the effects of gas and solids, as discussed in [12].

Corrosive well environments can make ESP usage challenging as well. A successfully integrated chemical program with ESP usage can prove to be very labor intensive and can take some time to get ironed out initially.

Typically, operators will go through a few ESPs of various sizes before recognizing that ESP is no longer the best form of artificial lift to use for the well. As the production rate decreases, the size of the pump will also decrease in an effort to keep the cost down. Eventually, running an ESP is not the most economical solution for the well and the operator must move on to another form of lift.Traditionally, the two top choices in this scenario are rod pumps and gas lift.

In the following sections, gas lift and rod lift as an alternate form of lift, as well as the benefits and challenges they represent are discussed.

GAS LIFT

Gas lift, particularly high-pressure gas lift, is often regarded as a very viable alternative to ESPs. Gas lift is often regarded as a sort of “cradle to grave” approach, as it can be designed to handle well production from well inception to depletion. It is a great alterative for numerous reasons. Gas lift is not as susceptible to detrimental factors as ESPs ensuring long-term successful operation.

It can achieve the same production rates at matched GLRs and, unlike ESPs, can be more easily installed on wells marked by large deviations and dog leg severity. It also has a clear advantage to ESPs in that it responds much better to produced sand and sediment as well as can be operated across a broader range of GLRs.

Successful chemical treatment is ~~also~~ much easier and less labor intensive than ESPs, as the natural flow of gas to the injection point can carry the crucial treatments to desired depths within the well bore.

When gas lift is chosen as the primary lift method, it can be designed to accommodate a wide range of production rates. High pressure gas lift can prove to be even more advantageous if the infrastructure exists to support the application. Greater differential pressures allow for the lifting of larger fluid columns and can yield greater well drawdown with less downhole equipment and less injection gas volumes. High pressure gas lift, like conventional gas lift, can also be setup to function as a “hybrid” system to provide means for annular flow from production onset with the option to be flipped to tubing flow once natural decline occurs without the need for intervention. This approach saves operators an abundance of capital and minimizes the need for costly downtime and potential intervention operations.

In 2017, an SPE paper publication authored by William Elmer, et.al suggested that annular single point high pressure gas lift (SPHPGL) could produce large liquid volumes and was a potential viable alternative to ESPs. At the time of publication, the authors provided nodal data to support their claims but did not have concrete field test data to support it, nor did they have immediate access to high discharge compressors. In 2018, as rental compressors became available, SM Energy, a Permian operator, agreed to assist with a pilot test in Howard County to evaluate the conclusions. Surface facilities were outfitted to handle increased production rates, and the findings were that the production rates were very close to the nodal claims outlined by the authors in 2017, and comparable to flow rates achieved by ESPs at lower costs, see [11].

A gas lift system, if properly designed, can be used for the entire life of the field with minimum or no modifications. Formation pressure and formation gas production, which decrease as the well depletes, are the most significant formation parameters to consider for gas lift design. Declining reservoir pressure is not a problem for the application of gas lift as the flowing bottom hole pressure (FBHP) can always be reduced to comply with the drop of formation pressure.

For initial high reservoir pressure, continuous lift is selected and then can be converted to intermittent gas lift as the formation pressure drops. Eventually, when the formation pressure is low enough, plunger assisted gas lift can be employed.

In the next section, the application of rod lift as a secondary form of lift is discussed.

ROD LIFT & LONG STROKE UNITS

This section discusses the history and demand of linear long stroke pumping units in the market today, challenges operators are facing using other forms of artificial lift in this specific volume range, as well as discuss case studies and field data. This paper also covers the technologies being utilized such as pumping unit selection, bottom hole assembly (BHA) and pump configurations, rod designs, and optimization with VSD 12 zone control, advancements in algorithms available for optimization such as plunger velocity, iteration on viscous damping and deviated downhole data models.

Rod lift has historically been used for aging wells with declining production rates. With advances in technology and increasingly challenging wells, there has been a considerable effort to convert to rod lift sooner in the lifecycle of the well.

ESPs commonly perform poorly in low volume lift applications, and they can present many challenges in these production ranges (300-500 BFPD range). Although operators are converting to a second or third ESP above this volume range, a rapid decline in the well’s production curve means that shortly after running another ESP the well will draw down quickly to a range where adverse issues may present themselves. Early conversion to rod pumps allows the operator to achieve drawdown into the 400-500 BFPD range without having to run multiple expensive ESPs into failure.

The main challenge with running another ESP is high OPEX and CAPEX costs. There are high upfront costs with ESPs. The initial ESP can utilize upwards of a 450-475 HP motor, and the second ESP a 300-350 HP motor, which can lead to high energy costs. Operators can save on energy costs with rod lift; the highest horsepower requirement with these systems is 150 HP. Converting wells to rod lift can present a somewhat high initial cost, however, one should take into account that it is a form of lift that will last throughout the well's lifecycle.

Another commonly considered alternative is gas lift, but long compressor lead times and limited infrastructure availability is a challenge that many operators face regularly. Injection gas distribution is an important factor when deciding between gas lift and rod lift. Having the flexibility to remove 400-700 BFPD wells off gas lift and reallocate the injection gas to higher priority wells, is a strong differentiator for operators.

The technology of long stroke linear units has been around for quite some time, they have become more prevalent in recent years. These units originated in the early 1980s by Jerry Lang and Gordon Lively in East Texas1, see [7]. In the past 40+ years, the primary push for these units has been to lift fluid from deeper wells, maximize downhole component life, and improve efficiencies.

Initially, some of the early versions of these units were not received well by operators due to the lack of safety mechanisms on the units and limited qualified service/repair professionals to maintain units. There have been many improvements in both areas since their inception; safety features have improved significantly, and the number of trained service professionals has increased.

The use of linear long stoke units in our industry today is driven by higher production demands in horizonal well applications. Stroke length trends have been steadily increasing over the past decade, as seen in figure 1. This growth in stroke length is primarily due to many horizontal wells coming off initial high-volume forms of lift, and in need of rod lift sooner in their lifecycle.

As can be seen in Figure 1, the demand for high volume rod lift in the form of large conventional beam units and linear long stroke units has never been greater than it is today. The data shown in this figure is the average stroke length of the pumping units installed by Liberty Lift Solutions in the given year. Note that Figure 1 reflects pumping units sold up to January 2025, therefore does not encompass a forecast of pumping units to be sold in 2025, merely an up to date snapshot.

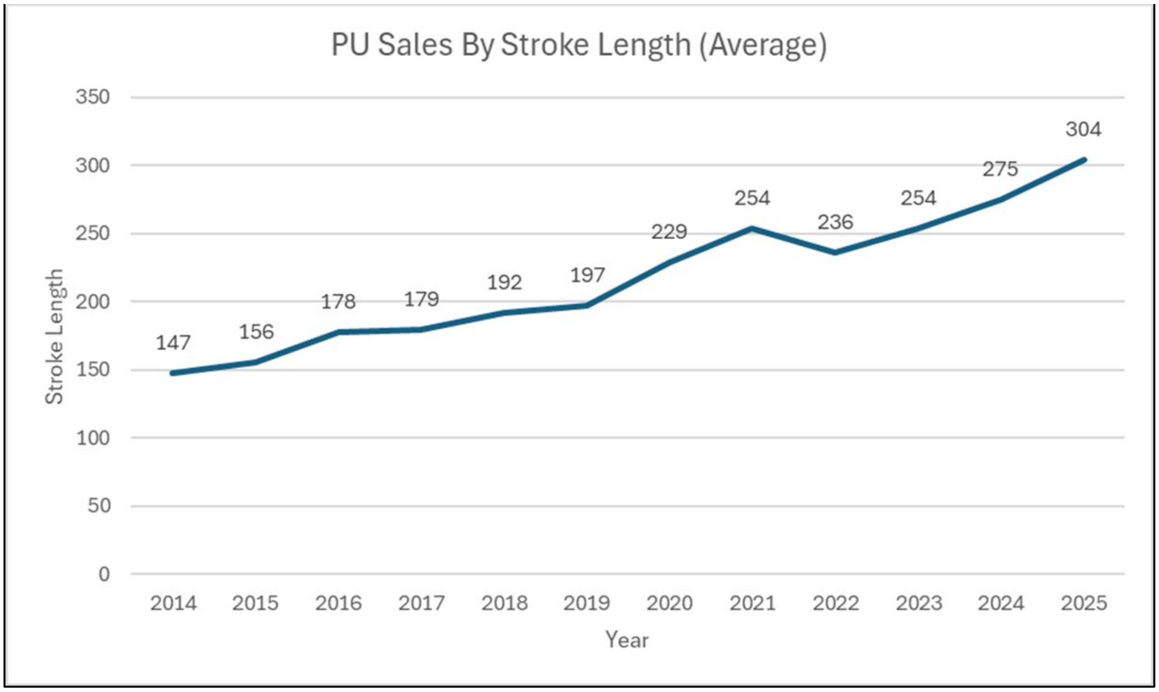

Figure 1: Stroke length trends 2015 2023.

In an effort to convert to rod lift sooner, operators have explored several options. The two main rod lift options are large conventional beam pumping units paired with fiberglass sucker rods or linear long strokes pumping units with steel sucker rods. As seen in figure 2, operators have been able to achieve notable production numbers (300-400 BFPD) utilizing beam pumping units (ranging from 640s-1280s), as per [3]. In order to achieve these production rates with larger beam units, it is important to consider that these units must run fast (7-10 SPM) to achieve this level of production. Operating a pumping unit at this speed increases failure rates and decreases the longevity of the installation. Viscous forces are proportional to the velocity of the rod string, therefore running the unit faster only increases the viscous dynamics the rod lift system has to overcome. Combined with shorter cycles and more frequent pump off events, higher risks for the installation follow.

Running much slower than the conventional units (2.5-4.0 SPM), linear long stokes can achieve 400-700 BFPD depending on wellbore conditions, which allows the operator to optimize pump efficiency and extend downhole component life by reducing cycles on the system. Having stroke lengths of 288–416 inches, make higher production rates, like those mentioned above, possible in wells as deep as 10,000 feet measured depth (MD).

This production range (400-700 BFPD) can represent a grey area for operators as seen in figure 2, where the operator must decide between running another ESP, installing gas lift system, which might compromise their run times and efficiencies. Linear long stroke units present another alternative allowing operators to maintain production and system longevity.

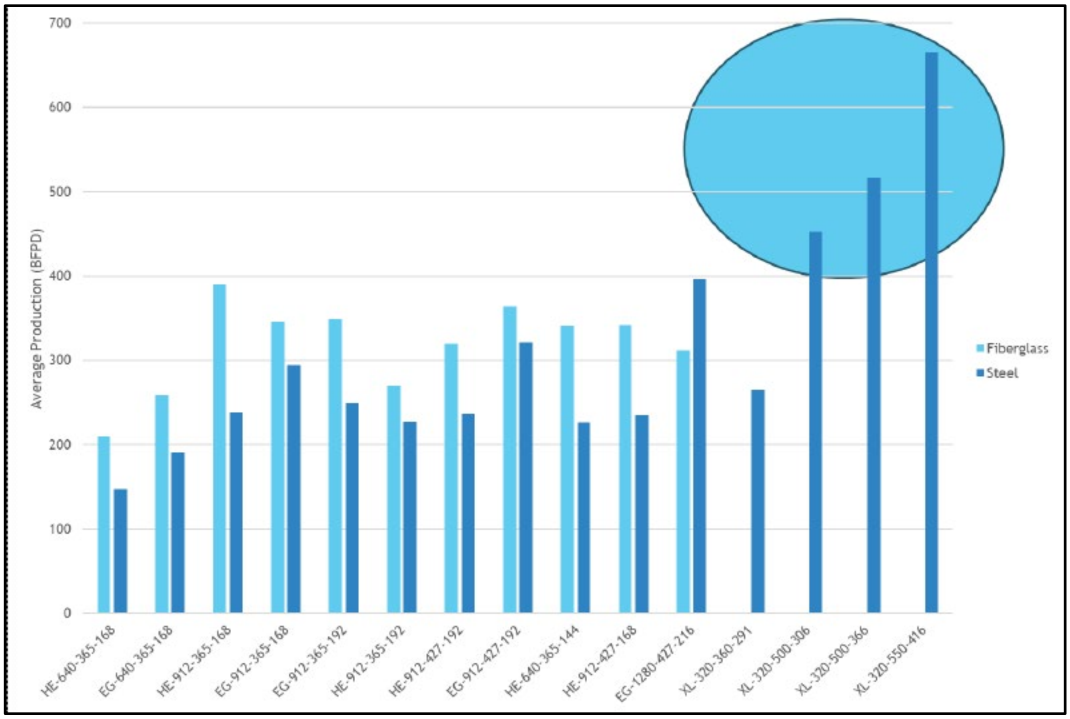

Figure 2: Rod Lift Production Trends by Unit Size (7000-10500ft)

GENERAL DESIGN

There are several aspects to consider when designing a rod lift system, much like that of ESPs and gas lift. Having comprehensive, and accurate, data gathering is imperative to formulate the most effective and efficient rod lift system design tailored for current well conditions. This holds especially true when transitioning to a high-volume system employing a linear long stroke unit.

Beyond conventional input parameters needed to create a software rod design, it is also important to account for historic well data encompassing corrosion, solids, gas/fluid production, and pump intake pressures/fluid levels. It is important to consider the primary goal and use this data to obtain that objective. On a base level this can be broken down into two major intentions, to maximize production rate or to optimize system longevity. Pursuing higher production rates at increased speeds may potentially compromise the longevity of downhole components, whereas prioritizing longevity may impede top-end production rates.

Technology advancements increasing the structural capacity and stroke lengths of linear long stroke units, coupled with the integration of new safety features, has considerably expanded the capability to increase fluid production, via a rod lift system. These units have a variety of stroke lengths from 288 inches to 416 inches, with structural ratings reaching up to 60,000 pounds as can be seen in table 1.

Reducer (lbs)	Structure (lbs)	Stroke Length (in)	Max SPM Range with VSD*	Max Production Range** (~5000’)	Max Production Range** (~9000’)
250,000	30,000	288	4.75 - 5.25	500	N/A***
320,000	36,000	291	4.75 - 5.25	500	N/A***
320,000	50,000	306	4.25 – 4.75	650	550
320,000	50,000	366	4.0 – 4.5	800	550
500,000	60,000	366	4.0 – 4.5	800	600
320,000	55,000	416	3.8 – 4.3	975	650 - 850

Table 1: Typical linear long-stroke pumping unit specifications

*Average SPMs are estimated based on well conditions
**Max production range estimated based on producing well data
***May not be applicable for high production ranges in deviated wells

Table 1 displays the technical specifications for the six most common linear long stroke units available in the current North American market. The table also highlights the maximum production rate ranges by unit and depth as observed in practice.

It should be noted that most high-volume applications require these units to run at higher end of their speed range. This necessitates the installation of a variable speed drive (VSD) to achieve these faster speeds due to the inherent mechanical characteristics of the units.

The main consideration when selecting a VSD is to relate it to the size of the pumping unit motor. Ideally, the drive horsepower (HP) should be equal to or greater than the pumping unit motor. For example, a 75 HP variable speed drive can work on a 60 HP motor but a 60HP VSD cannot work with a 75 HP motor. The only exception to this rule is when operating on single phase power. In this case, the rule of thumb is to double the VSD size. If there are not any harmonic requirements from the co-op or power company, then a standard 6 pulse drive will suffice. However, if low harmonics are required, it is recommended to go with an Active Front end drive or add harmonic filters to the standard 6 pulse drive.

It is important to acknowledge that each unit presents its own set of advantages and constraints. For relatively shallow applications, such as those around 5000 feet, approximately 550 BFPD can be yielded with a unit that has a structural capacity of 36,000 pounds and a stroke length of 288/291 inches. However, to achieve production rates exceeding 650 BFPD at depths nearing 9000 feet, depending on wellbore conditions, a unit featuring a higher structural capacity, such as 55,000 pounds, and a longer stroke length, of 416 inches, may be needed. This scenario requires greater horsepower than smaller long stroke units and may require the utilization of tubing pumps in a 2-7/8-inch tubing application.

Once the base goal of system longevity versus maximum production rate is outlined and a design is finalized it is crucial to carefully select the downhole equipment: BHA, gas separator, and downhole pump design. An inadequately sized BHA and downhole pump configurations can significantly limit high-volume production and cause premature system failures.

CASING SIZE	COMPANY NAME	TOOL STYLE	CROSS SECTIONAL SEPARATION AREA π (R^2-r^2)	SEPARATION AREA (in^2) (D^2-d^2) For Volume Calculation	FLUID VOLUME	LENGTH OF TOOL (IN)	STORAGE CAPACITY (bbl)
4.5”	Company 1 & 2	2-3/8” Packer Style Separator	8.14	10.36	348	480	0.40253
4.5”	Company 1	2-7/8” Packer Style Separator	6.07	7.73	260	480	0.30054
4.5”	Company 2	2.5” Mother Hubbard	3.43	4.37	147	300	0.10605
4.5”	**Liberty Lift**	**3” HALO**	**3.11**	**3.96**	**133**	**240**	**0.07694**
4.5”	**Liberty Lift**	**THE MAX**	**9.73**	**12.39**	**416**	**480**	**0.48144**
5.5”	Company 1 & 2	2-3/8” Packer Style Separator	13.67	17.40	585	480	0.67609
5.5”	Company 1	2-7/8” Packer Style Separator	11.60	14.77	497	480	0.57409
5.5”	Company 1	3.5” Packer Style Separator	8.47	10.79	363	480	0.41927
5.5”	Company 3	3.5” Mother Hubbard	6.03	7.68	258	120	0.07464
5.5”	Company 2	3” Mother Hubbard	6.03	7.68	258	300	0.1866
5.5”	Company 4	2-3/8” Mother Hubbard	2.26	2.88	97		
5.5”	Company 4	2-7/8” Mother Hubbard	3.32	4.23	142		
5.5”	**Liberty Lift**	**3.75” HALO**	**6.20**	**7.90**	**265**	**240**	**0.15344**
5.5”	**Liberty Lift**	**4.125” DOMINATOR**	**9.45**	**12.04**	**405**	**240**	**0.23388**
5.5”	**Liberty Lift**	**1.9” MAX**	**15.09**	**19.22**	**646**	**480**	**0.7458**
5.5”	**Liberty Lift**	**2-3/8” MAX**	**13.50**	**17.19**	**578**	**480**	**0.6679**
7”	Company 2	4” Mother Hubbard	11.37	14.48	487	300	0.35154
7”	Company 3	4/5” Mother Hubbard	10.57	13.45	452	120	0.13069
7”	**Liberty Lift**	**1.9” MAX**	**29.90**	**38.07**	**1280**	**480**	**1.47929**
7”	**Liberty Lift**	**2-3/8” MAX**	**28.31**	**36.04**	**1211**	**480**	**1.40038**
7”	**Liberty Lift**	**5” HALO**	**13.32**	**16.96**	**570**	**240**	**0.32951**
7-5/8”	Company 2	2-7/8” Packer Style Separator	30.63	39.00	1311	480	1.51543
7-5/8”	**Liberty Lift**	**3-1/2” MAX**	**27.50**	**35.02**	**1177**	**480**	**1.3606**

Figure 3: Overview of Liberty Lift’s BHA offerings

Figure 3 shows the different options for bottom hole assembly offered by Liberty Lift. The maximum production limitation of any BHA depends on the separation area of the tool and is based on an industry standard bubble point of 0.4 ft/sec, which affects the downward fluid velocity and therefore effective separation. As the reservoir pressure draws down below bubble point pressure, increasing volumes of free gas begin to break out of solution, see [1].

Downward fluid velocity is calculated using:

$$Downward\ Fluid\ Velocity = \frac{Total\ Bbls.Fluid * 0.0119}{(ID_{Csg})^2 - (OD_{Sep})^2}, \tag{1}$$

Where ID_{Csg} is the inner diameter of the casing and OD_{Sep} is the outer diameter of the separator.

A downward fluid velocity of 0.4 ft/sec is recommended for proper gas separation. In this instance, the gas stays in solution and can be more effectively produced with the fluids. The above equation can be manipulated to calculate the total barrels of fluids of production for which a separator will offer effective separation, based on a bubble point or downward fluid velocity of 0.4 ft/sec as shown in (2).

$$Total\ Bbls.Fluid = \frac{0.4 * [\left(ID_{Csg}\right)^2 - \left(OD_{Sep}\right)^2]}{0.0119}, \tag{2}$$

For instance, looking at the 4.125” Dominator, the production threshold beyond which separation is not guaranteed is

$$\frac{0.4*(3.625^2-1.05^2)}{0.0119} = 405\ BFPD.$$

One of the most important components of Rod Lift is the rod pump. The rod pump works as a positive displacement pump to move fluid from the reservoir to the surface. Sizing the rod pump properly will ensure a successful and economical rod lift system. The biggest consideration with selecting pump size is the size of the production tubing, the size of the casing, the stoke length of the unit, the depth of the seating nipple, and the target production range.

Table 2 displays the typical downhole pump lengths and bore diameters with corresponding base level constraints.

Unit Stroke Length	**291”**	**306”**	**366”**	**416”**
Max Insert Pump Diameter	2”	2”	2”	2”
Tubing Pump Diameter	2.25” or greater	2.25” or greater	2.25” or greater	2” or greater
Pump Length	36’	40’	42’	47’
Polished Rod Length	36’	40’	46’	50’

Table 2: Operations - API pump length, type, and bore size compatible with each linear long stroke unit.

Note that the 2” tubing pump for a 416” stroke length unit is a special non-API pump design. Also highlighted are the recommended polished rod lengths for each unit.
*Information based on 2.875’’ tubing

Once operational, adequate well spacing can enhance pump efficiency while mitigating the risk of pump tagging, which can cause premature pump damage. By leveraging a VSD and dynamometer cards, optimal system performance can be ensured. Continuous monitoring of the system design against controller outputs and ensuring proper well spacing are imperative. With VSD zone-control enabled, a system can be optimized for increased pump fillage by slowing down and speeding up at different portions of the stroke. Zone-control should also be utilized if running the unit at increased speeds.

Liberty Lift has commercialized a cloud-based pump-off controller that has access to boundless processing power and the ability to constantly improve by adding new features. Pump-off controllers monitor fillage to avoid conditions such as pump off when pumping rate exceeds the rate at which the reservoir supplies fluids to the wellbore.

Unfortunately, gas interference causes pump fillage to drop, which can be mistaken for pump off. In this case, pumping is stopped or slowed down, when it should be continued. The new added plunger velocity feature, seen in Figure 4, allows the operator to quickly and efficiently dissociate pump off from gas interference. This enables the operator to increase speed and safely achieve more production as opposed to slowing down the well and hindering it.

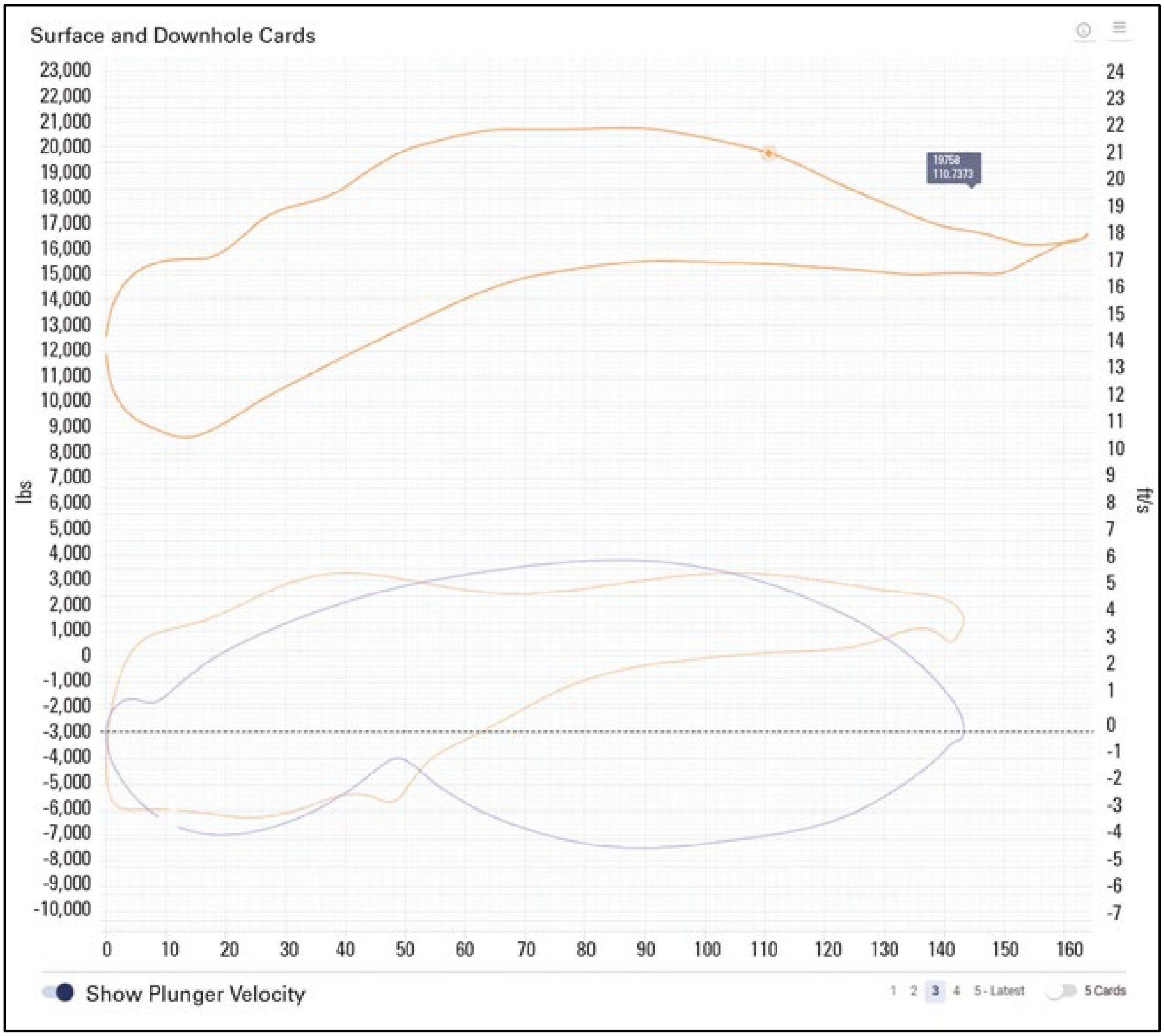

Figure 4: Plunger velocity card superimposed on the downhole card.

Figure 4 shows a surface card and the corresponding downhole card with the plunger velocity overlaid on top of the downhole card. In this example, the downhole card shows gas interference as is characterized by the sloped descent after the top of stroke. This downhole condition is verified by the plunger velocity plot, which shows that the plunger velocity does not go to zero which means the plunger did not stop and merely slowed down. In a pump off condition, the plunger abruptly stops as it hits the fluid, and the velocity of the plunger becomes momentarily zero.

Another important feature of the controller is the method of calculation of downhole data. Liberty lift not only offers a traditional vertical hole model (Gibbs), see [4], but a finite difference based model enhanced with iteration on viscous damping, cf. [10] and a deviated method capable of removing both viscous and mechanical friction from the downhole data, cf. [9].

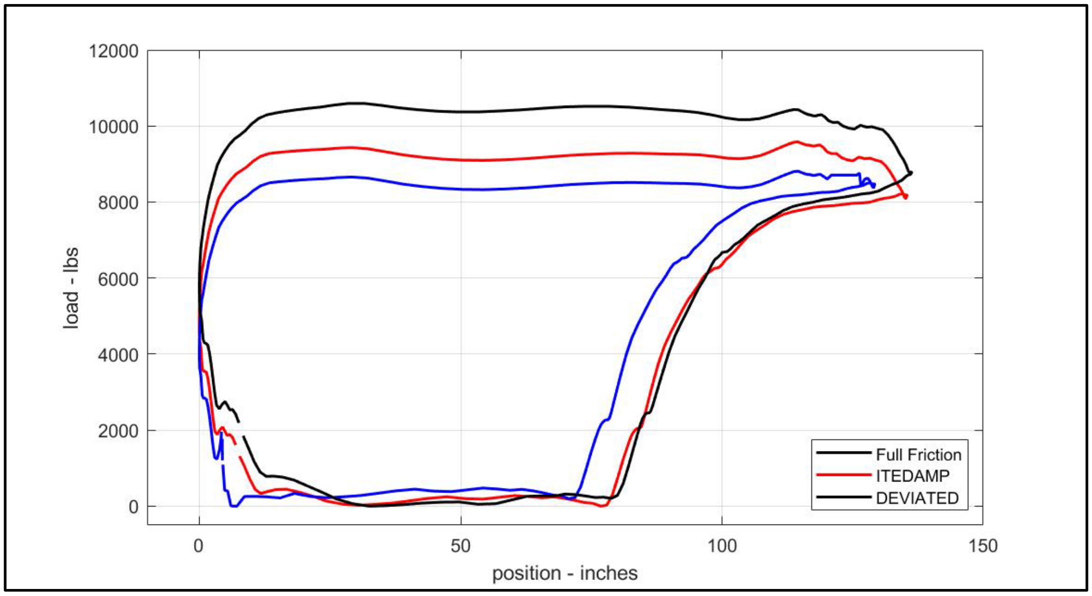

Figure 5: Comparison of downhole card with full friction (black), viscous friction removed (red) and both viscous and mechanical friction removed (blue).

Figure 5 shows the comparison between a traditional vertical hole model with no friction removed, depicted in black, an enhanced vertical hole model where viscous friction is adequately removed, in red, compared to a deviated model where both viscous and mechanical friction have been removed in blue.

Note the change in fluid load (vertical span of the card) and netstroke (horizontal span of the card that contains fluid). These quantities are critical for well control and optimization. Fluid load is used in pump intake pressure calculations and is essential when optimizing production of a well. Netstroke is the most important variable in inferred production calculations, which quantifies the amount of fluids produced.

Any error in calculation in these values greatly undermines any effort at proper optimization and production of a rod pumped well.

Having accurate reliable downhole data, which offers a friction free picture of the pump action is essential when optimizing a rod pump installation and assessing production.

Finally, an enhanced 12-zone control is implemented in the Ken Well Manager, which offers better control compared to the industry standard of 4 zones. Benefits associated with having the possibility to change the intra stroke speed 6 times during the upstroke and 6 times during the downstroke, allows the operator to maintain high speeds for longer periods during the stroke without putting the long stroke unit at risk. This enables more production at less risk to the installation. Also, a more gradual increase or decrease in SPM allows for more flexible operation within the acceleration limits that the drive imposes to protect itself. This approach reduces peak loads on equipment, as well as increases production and longevity of the installation.

Linear long stroke pumping units have proven to be a tested alternative in uplifting wells of varying volumes. While high-volume ESPs and gas lift systems will always have a place in the industry, linear long stroke units prove to be a viable alternative in applications with volumes of 400-900 BFPD. With adequate selection for both the pumping unit and downhole components, operators have the flexibility to chase maximum volumes or increase system longevity, based on their goal for the system.

RESULTS

1) Gas Lift

The results below summarize a case study performed by Estis Compression and SM Energy with the goal to compare the performance of Single-Point High-Pressure Gas Lift (SPHPGL) and ESPs. This case study was based on eight wells on two adjoining four well pads, seven equipped with ESPs and one with SPHPGL to provide a measurable comparison.

The motivation of this study was to utilize Single-Point High-Pressure Gas Lift to mitigate challenges such as solid production, highly deviated wellbores, increasing GOR over the life of the well and the steep decline from high initial production rates. All eight wells were completed on two adjoining pads utilizing the same casing configuration - 5-1/2” 20# P-110 from surface to toe. They were drilled in the same formation with an average total vertical depth of 8,150 feet and treated lateral length of 10,000 feet achieved. The wells containing ESP configurations were sized to accommodate flow rates of 4,000 to 4,500 barrels per day, which was dictated by historical data for the area.

Careful selection was made with regard to tubing size selection, tubing landing inclination and setting depth, well head configuration, and separator characteristics.

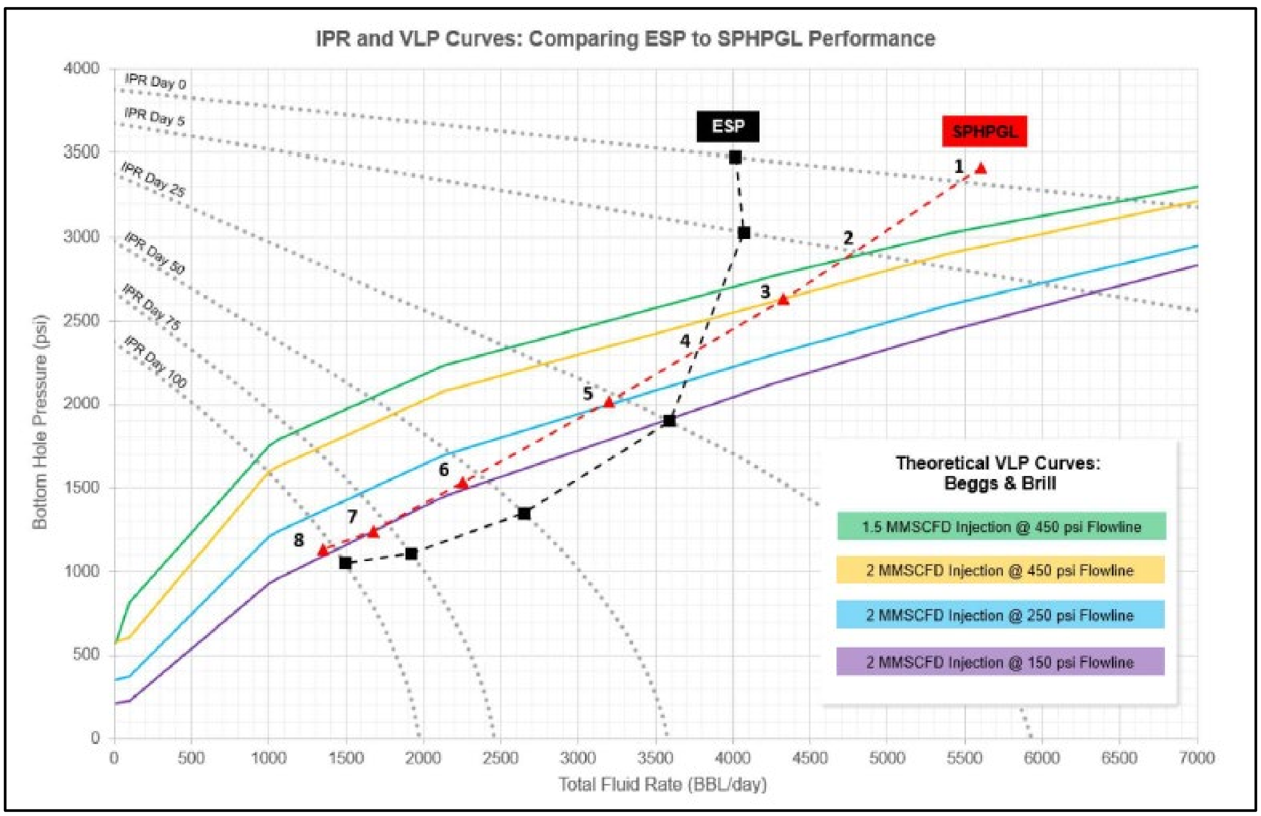

Figure 6: ESP and HPGL Performance curves from SPE 195180

Results of this study showed that SPHPGL exceeded production for the first 24 days and after 100 days was found to be similar to ESP. The cumulative production for both ESP and SPHPGL over the first 100 days was comparable.

Continuous and Intermittent gas lift can also be implemented on a well with solid or deviation issues. Since high pressure compression is not always available and every gas lift application does not require the use of SPHPGL, particularly as GORs increase and rates fall, a more conventional approach to gas lift may be employed.

In [8], Murski describes how gas lift valve design improvements have contributed to longer run times and ability to use gas lift in more challenging applications. In this paper, Murski describes the challenges that exist utilizing traditional injection pressure operated (IPO) valves in more demanding unconventional wells.

2) <u>Rod Pumps</u>

In some cases, it makes economic sense to reuse a pumping unit, there may already be one on the well or it may be necessary to move units around the field.

Figure 7 and 8 show a situation where fiberglass rods may be necessary to achieve the intended production rate. For example, there is a conventional 640-365-168 pumping unit on a 8000' deep well and it is expected to make ~400BFPD. Steel rods are too heavy for the gearbox and will not allow for such a high fluid rate. Fiberglass achieve overtravel by running fast. This means that if the 640 unit is run at 8SPM with fiberglass rods and a 1.75" pump, it can produce ~430BFPD. No portion of the system is overloaded, and the expected production rate has been met. The same production rate could be achieved with a linear unit, but the gearbox (GB) is only loaded to 50% and the structure rating is 65%, it is not an efficient system and will cost more to set up than using the existing 640 pumping unit.

It is always good to look at many options to determine what rod lift design might be best suited for each well. When attempting to reach max production possible, often, a linear long stroke unit with a steel string is the best solution.

Figures 9, 10 and 11 show three rod designs comparing different units and rod configurations to determine the best option for maximum production.

Looking at Figure 10, an 8000' well with minimal deviation we find that using a steel string on a conventional 1280-365-192 with a 1.75" pump at 6SPM results in a production rate of ~380BFPD. In this case the GB is loaded at 95% and the structure rating is 98%; the load needs to be reduced. Before using a larger unit, it is important to check and see if a fiberglass string is an option.

By using fiberglass, see Figure 11, the GB and unit structure loading was reduced, which allowed for an increase in speed and pump size. The maximum suggested speed for a 192" stroke length is 7.5SPM. At the max speed with fiberglass rods and a 2.00" pump the production rate possible on the 1280-365-192 was increased to ~550BFPD.

In this case the maximum recommended speed of this unit is the limiting factor. If attempting to further increase the production rate it is time to look at a linear long stroke unit. The longest stroke currently available on a linear unit is 416", see Figure 9. By using this unit, the pump size can be increased to a 2.25" tubing pump, which results in a production rate of ~800BFPD.

RODSTAR 2023 REL 3

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Well: User:

Disk file:RodStar Example_XL 366 Steel vs HE FG.rsdx Date:3/7/2025

Comment:

INPUT DATA

Strokes per minute:	3.8	Pump int. pr. (psi):	600
Run time (hrs/day):	24.0	Fluid level	
Tubing pres. (psi):	150	(ft over pump):	1374
Casing pres. (psi):	100	Stuf.box fr. (lbs):	100
		Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	85%
Water sp. gravity:	1.05
Oil API gravity:	42.0
Fluid sp. gravity:	1.0148

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit:Liberty XL LS (XL320-500-366)

API Size: R-320-500-366 (Unit ID: LSLIB3)

Crank hole number:	# 1 (out of 1)
Calculated stroke length (in):	366
Crank rotation with well to right:	CCW
Max. cb weight (M lbs):	Unknown

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	8000	Tub.anch.depth (ft):	7900
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	1.75	Pump friction (lbs):	600.0

CALCULATED RESULTS

Production rate (bfpd):	417	Peak pol. pod load (lbs):	32479
Oil production (BOPD):	63	Min. pol. rod load (lbs):	12844
Strokes per minute:	3.8	MPRL/PPRL:	0.395
System eff. (Motor->Pump):	44%	Unit struct. loading:	65%
Permissible load HP:	136		
Fluid load on pump (lbs):	7408	PRHP / PLHP:	0.28
Fluid level tvd (ft from surface):	6626	Buoyant rod weight (lbs):	18494
Polished rod HP:	38.2	N/No: .112 , Fo/SKr: .095	

Required prime mover size (speed var. not included)	BALANCED (Min. Energy)	BALANCED (Min Torq)
NEMA D motor:	60 HP	50 HP
Single/double cyl. engine:	50 HP	50 HP
Multicylinder Engine:	60 HP	50 HP

Torque analysis and electricity consumption	BALANCED (Min. Energy)	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	185	165
Gearbox loading:	57.8%	51.5%
Cyclic load factor:	1.071	1.045
Counterbalance weight(M lbs):	23.88	22.66
Daily electr.use (Kwh/Day):	825	845
Monthly electric bill:	$1509	$1546
Electr.cost per bbl fluid:	$0.119	$0.122
Electr.cost per bbl oil:	$0.791	$0.810

Tubing, Pump And Plunger Calculations

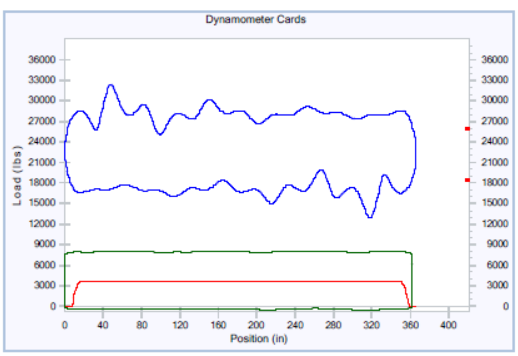
Tubing stretch (in):	.2
Prod. loss due to tubing stretch (bfpd):	0.2
Gross pump stroke (in):	361.9
Pump spacing (in. from bottom):	40.1
Minimum pump length (ft):	42.0
Recommended plunger length (ft):	6.0

Rod string design (rod tapers calculated) / **Rod string stress analysis (service factor: 1)**

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
+ 1	LLDS-KDT/2.8	1975	125000	0.22	72.1%	41226	16481	12500	API MG T/2.8
0.875	LLDS-KDT/2.8	5425	125000	0.22	72.1%	40887	15860	332	API MG T/2.8
@ 1.5	Flexbar C	600	90000	0.22	65.0%	13719	-1264	-340	API MG

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).

NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



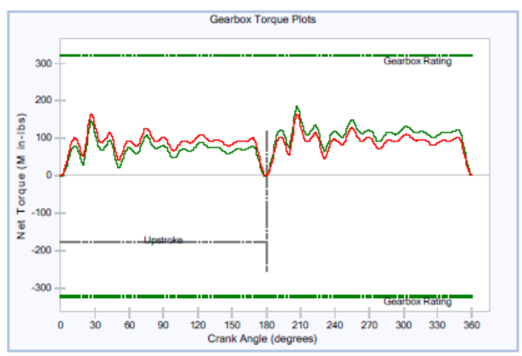


Figure 7: Rod design results using Rodstar for XL 366 steel vs. HE FG

RODSTAR 2023 REL 3

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Well: User:

Disk file:RodStar Example_HE FG_reuse smaller unit.rsd Date:3/7/2025

Comment:

INPUT DATA

Strokes per minute:	8	Pump int. pr. (psi):	600
Run time (hrs/day):	24.0	Fluid level (ft over pump):	1374
Tubing pres. (psi):	150	Stuf.box fr. (lbs):	100
Casing pres. (psi):	100	Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	85%
Water sp. gravity:	1.05
Oil API gravity:	42.0
Fluid sp. gravity:	1.0148

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit:Liberty HE Conventional

API Size: C-912-365-168 (Unit ID: CLY1)

Crank hole number:	# 1 (out of 3)
Calculated stroke length (in):	168.7
Crank rotation with well to right:	CCW
Max. cb moment (M in-lbs):	Unknown
Structural unbalance (lbs):	-600
Crank offset angle (degrees):	0.0

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	8000	Tub.anch.depth (ft):	7900
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	1.75	Pump friction (lbs):	600.0

CALCULATED RESULTS

Production rate (bfpd):	429	Peak pol. pod load (lbs):	28635
Oil production (BOPD):	64	Min. pol. rod load (lbs):	9515
Strokes per minute:	8	MPRL/PPRL:	0.332
System eff. (Motor->Pump):	37%	Unit struct. loading:	78%
Permissible load HP:	88.5	PRHP / PLHP:	0.46
Fluid load on pump (lbs):	7408		
Fluid level tvd (ft from surface):	6626	Buoyant rod weight (lbs):	14323
Polished rod HP:	40.6	N/No: .396 ,	Fo/SKr: .324

Required prime mover size (speed var. not included) — BALANCED (Min Torq)

NEMA D motor:	100 HP
Single/double cyl. engine:	75 HP
Multicylinder Engine:	100 HP

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	879
Gearbox loading:	96.4%
Cyclic load factor:	1.559
Max. cb moment (M in-lbs):	1648.1
Counterbalance effect(lbs):	20090
Daily electr.use (Kwh/Day):	1025
Monthly electric bill:	$1876
Electr.cost per bbl fluid:	$0.143
Electr.cost per bbl oil:	$0.955

Tubing, Pump And Plunger Calculations

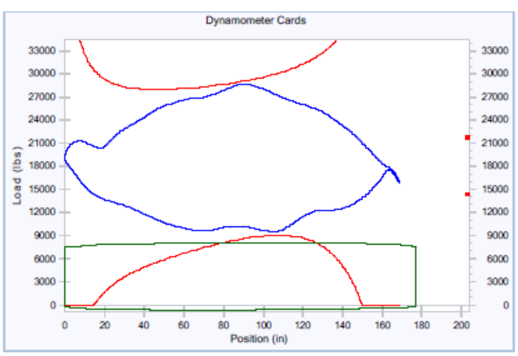
Tubing stretch (in):	.2
Prod. loss due to tubing stretch (bfpd):	0.4
Gross pump stroke (in):	177.0
Pump spacing (in. from bottom):	50.2
Minimum pump length (ft):	27.1
Recommended plunger length (ft):	6.0

Rod string design / Rod string stress analysis (service factor: 1)

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1.24	Fiberflex API	3800	N/A	0.2	76.7%	23629	7962	6242	0
+ 1	LLDS-KDT/2.8	2000	125000	0.2	53.3%	29840	9061	3978	0
0.875	LLDS-KDT/2.8	1500	125000	0.2	54.5%	26832	3809	1360	0
@ 1.5	Flexbar C	700	90000	0.2	64.3%	14128	-457	-340	0

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).

NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



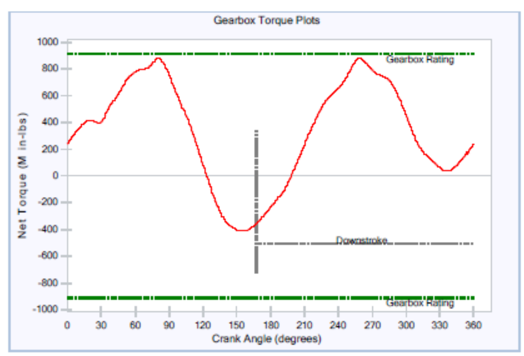


Figure 8: Rod design results using Rodstar for HE FG to reuse smaller units

RODSTAR 2023 REL 3

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Company:
Well:
Disk file:RodStar Example_XL 416 Steel max production.ı
Comment:

User:
Date:3/7/2025

INPUT DATA

Strokes per minute:	4	Pump int. pr. (psi):	600
Run time (hrs/day):	24.0	Fluid level	
Tubing pres. (psi):	150	(ft over pump):	1374
Casing pres. (psi):	100	Stuf.box fr. (lbs):	100
		Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	85%
Water sp. gravity:	1.05
Oil API gravity:	42.0
Fluid sp. gravity:	1.0148

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit:Liberty XL LS (XL320-550-416)

API Size: R-320-550-416 (Unit ID: LSLIB4)

Crank hole number:	# 1 (out of 1)
Calculated stroke length (in):	416
Crank rotation with well to right:	CCW
Max. cb weight (M lbs):	Unknown

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	8000	Tub.anch.depth (ft):	7900
Pump conditions:	Full		
Pump type:	Tubing	Pump vol. efficiency:	85%
Plunger size (in):	2.25	Pump friction (lbs):	600.0

CALCULATED RESULTS

Production rate (bfpd):	793	Peak pol. pod load (lbs):	37802
Oil production (BOPD):	119	Min. pol. rod load (lbs):	11262
Strokes per minute:	4	MPRL/PPRL:	0.298
System eff. (Motor->Pump):	52%	Unit struct. loading:	69%
Permissible load HP:	163	PRHP / PLHP:	0.40
Fluid load on pump (lbs):	12246		
Fluid level tvd (ft from surface):	6626	Buoyant rod weight (lbs):	18518
Polished rod HP:	65.3	N/No: .084 ,	Fo/SKr: .131

Required prime mover size (speed var. not included) — BALANCED (Min Torq)

NEMA D motor:	100 HP
Single/double cyl. engine:	100 HP
Multicylinder Engine:	100 HP

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	223
Gearbox loading:	69.6%
Cyclic load factor:	1.062
Counterbalance weight(M lbs):	24.53
Daily electr.use (Kwh/Day):	1358
Monthly electric bill:	$2485
Electr.cost per bbl fluid:	$0.103
Electr.cost per bbl oil:	$0.685

Tubing, Pump And Plunger Calculations

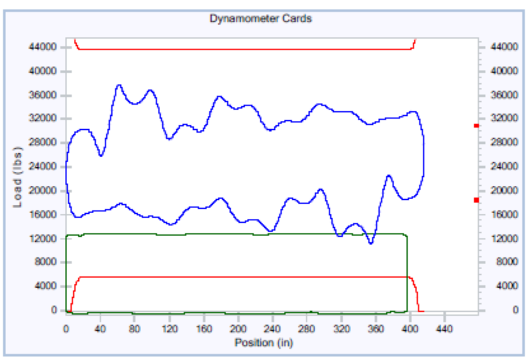
Tubing stretch (in):	.3
Prod. loss due to tubing stretch (bfpd):	0.5
Gross pump stroke (in):	395.5
Pump spacing (in. from bottom):	40.8
Minimum pump length (ft):	48.0
Recommended plunger length (ft):	6.0

Rod string design (rod tapers calculated) / Rod string stress analysis (service factor: 1)

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
+ 1	LL HA	2625	140000	0.2	81.9%	48004	14466	8419	API MG T/2.8
0.875	LL HA	2925	140000	0.2	82.3%	46186	10401	292	API MG T/2.8
+ 1	LL HA	2450	140000	0.2	55.8%	27305	-933	-764	API MG T/2.8

+requires slimhole couplings.

NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



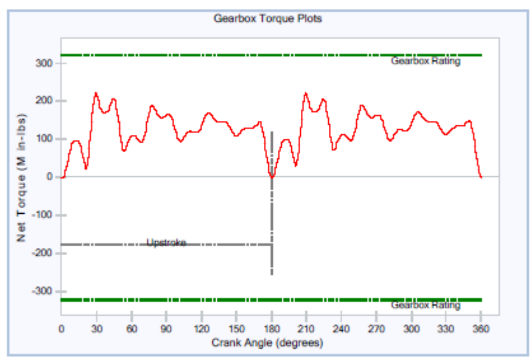


Figure 9: Rod design using Rodstar featuring XL 416 to maximize production

RODSTAR 2023 REL 3

Company: © Theta Oilfield Services, Inc. (gotheta.com) Page 1 of 11
Well: User:
Disk file:RodStar Example_HE1280 Steel_max productior Date:3/7/2025
Comment:

INPUT DATA				CALCULATED RESULTS			
Strokes per minute:	6	Pump int. pr. (psi):	600	Production rate (bfpd):	387	Peak pol. rod load (lbs):	35878
Run time (hrs/day):	24.0	Fluid level (ft over pump):	1374	Oil production (BOPD):	58	Min. pol. rod load (lbs):	11923
Tubing pres. (psi):	150	Stuf.box fr. (lbs):	100	Strokes per minute:	6	MPRL/PPRL:	0.332
Casing pres. (psi):	100	Pol. rod. diam.	1.5"	System eff. (Motor->Pump):	42%	Unit struct. loading:	98%
				Permissible load HP:	84.7	PRHP / PLHP:	0.40
				Fluid load on pump (lbs):	9676	Buoyant rod weight (lbs):	18680
				Fluid level tvd (ft from surface):	6626	N/No: .176 ,	Fo/SKr: .231
				Polished rod HP:	33.8		

Fluid Properties

Water cut:	85%
Water sp. gravity:	1.05
Oil API gravity:	42.0
Fluid sp. gravity:	1.0148

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Required prime mover size (speed var. not included) — BALANCED (Min Torq)

NEMA D motor:	75 HP
Single/double cyl. engine:	60 HP
Multicylinder Engine:	75 HP

Pumping Unit:Liberty HE Conventional

API Size: C-1280-365-192 (Unit ID: CLY5)

Crank hole number:	# 1 (out of 3)
Calculated stroke length (in):	192
Crank rotation with well to right:	CW
Max. cb moment (M in-lbs):	Unknown
Structural unbalance (lbs):	-620
Crank offset angle (degrees):	0.0

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	1226
Gearbox loading:	95.8%
Cyclic load factor:	1.49
Max. cb moment (M in-lbs):	2411.28
Counterbalance effect(lbs):	25838
Daily electr.use (Kwh/Day):	820
Monthly electric bill:	$1500
Electr.cost per bbl fluid:	$0.127
Electr.cost per bbl oil:	$0.847

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	8000	Tub.anch.depth (ft):	7900
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	2	Pump friction (lbs):	600.0

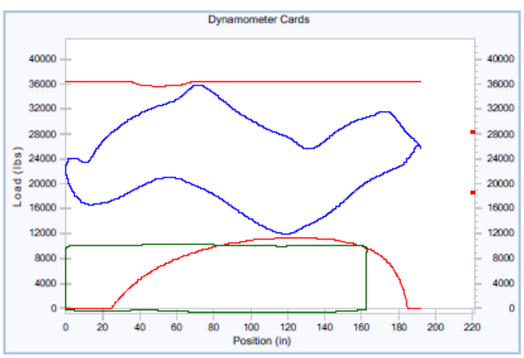
Tubing, Pump And Plunger Calculations

Tubing stretch (in):	.2
Prod. loss due to tubing stretch (bfpd):	0.5
Gross pump stroke (in):	163.0
Pump spacing (in. from bottom):	24.0
Minimum pump length (ft):	26.0
Recommended plunger length (ft):	6.0

Rod string design | **Rod string stress analysis (service factor: 1)**

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1	LLDS-KDT/2.8	2775	125000	0.2	86.2%	45553	15309	8444	0
0.875	LLDS-KDT/2.8	4725	125000	0.2	84.8%	42742	10403	437	0
@ 1.5	Flexbar C	500	90000	0.2	69.9%	14896	-1203	-340	0

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).
NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



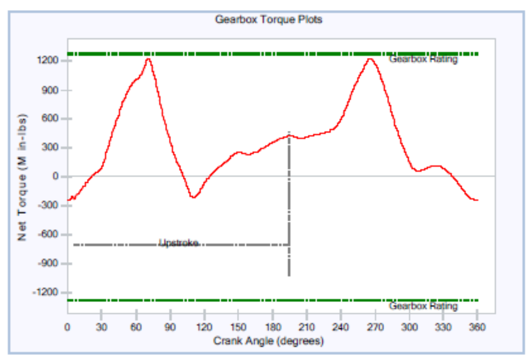


Figure 10: Rod design using Rodstar featuring HE 1280 steel to maximize production

RODSTAR 2023 REL 3

Company: | © Theta Oilfield Services, Inc. (gotheta.com) | Page 1 of 11

Well: | User:

Disk file:RodStar Example_HE1280 FG_max production.r | Date:3/7/2025

Comment:

INPUT DATA

Strokes per minute:	7.5	Pump int. pr. (psi):	600
Run time (hrs/day):	24.0	Fluid level (ft over pump):	1374
Tubing pres. (psi):	150	Stuf.box fr. (lbs):	100
Casing pres. (psi):	100	Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	85%
Water sp. gravity:	1.05
Oil API gravity:	42.0
Fluid sp. gravity:	1.0148

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit:Liberty HE Conventional

API Size: C-1280-365-192 (Unit ID: CLY5)

Crank hole number:	# 1 (out of 3)
Calculated stroke length (in):	192
Crank rotation with well to right:	CCW
Max. cb moment (M in-lbs):	Unknown
Structural unbalance (lbs):	-620
Crank offset angle (degrees):	0.0

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	8000	Tub.anch.depth (ft):	7900
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	2	Pump friction (lbs):	600.0

CALCULATED RESULTS

Production rate (bfpd):	552	Peak pol. pod load (lbs):	31217
Oil production (BOPD):	83	Min. pol. rod load (lbs):	7998
Strokes per minute:	7.5	MPRL/PPRL:	0.256
System eff. (Motor->Pump):	41%	Unit struct. loading:	86%
Permissible load HP:	111.9	PRHP / PLHP:	0.44
Fluid load on pump (lbs):	9676	Buoyant rod weight (lbs):	14149
Fluid level tvd (ft from surface):	6626	N/No: .373 ,	Fo/SKr: .379
Polished rod HP:	49.3		

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	100 HP
Single/double cyl. engine:	100 HP
Multicylinder Engine:	100 HP

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	1112
Gearbox loading:	86.9%
Cyclic load factor:	1.484
Max. cb moment (M in-lbs):	1975.7
Counterbalance effect(lbs):	21059
Daily electr.use (Kwh/Day):	1190
Monthly electric bill:	$2178
Electr.cost per bbl fluid:	$0.129
Electr.cost per bbl oil:	$0.863

Tubing, Pump And Plunger Calculations

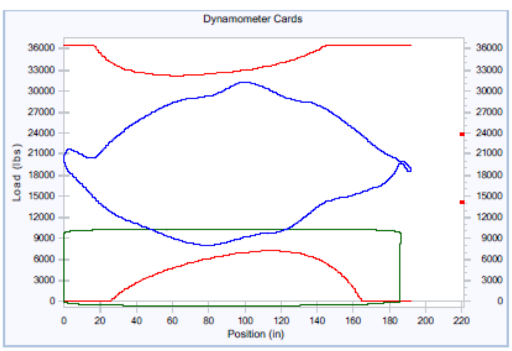
Tubing stretch (in):	.2
Prod. loss due to tubing stretch (bfpd):	0.6
Gross pump stroke (in):	185.9
Pump spacing (in. from bottom):	52.0
Minimum pump length (ft):	28.6
Recommended plunger length (ft):	6.0

Rod string design / **Rod string stress analysis (service factor: 1)**

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1.24	Fiberflex API	4000	N/A	0.2	92.4%	25767	6706	5441	0
+ 1	LLDS-KDT/2.8	2100	125000	0.2	62.0%	32459	7803	3265	0
0.875	LLDS-KDT/2.8	1200	125000	0.2	62.5%	29556	2691	1371	0
@ 1.5	Flexbar C	700	90000	0.2	78.4%	17347	-449	-340	0

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).

NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



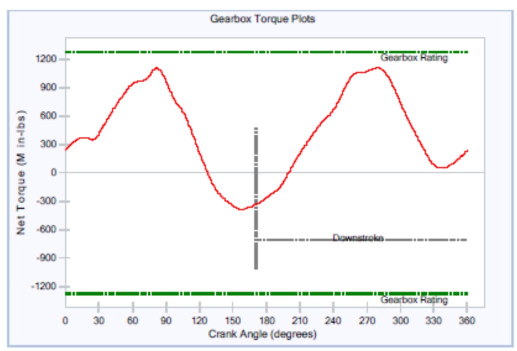


Figure 11: Rod design using Rodstar featuring HE 1280 fiberglass to maximize production

Every well has a design that works best for it. Depth, deviation, wellbore properties, and economics are the basis on which designs are built. It is hard to compare designs as apples to apples as they all have their place in certain situations.

It is important when going into a rod lift design to determine what your goal is and try to optimize the well accordingly, this is the key to being successful.

3) <u>Operator Results</u>

a. ESP

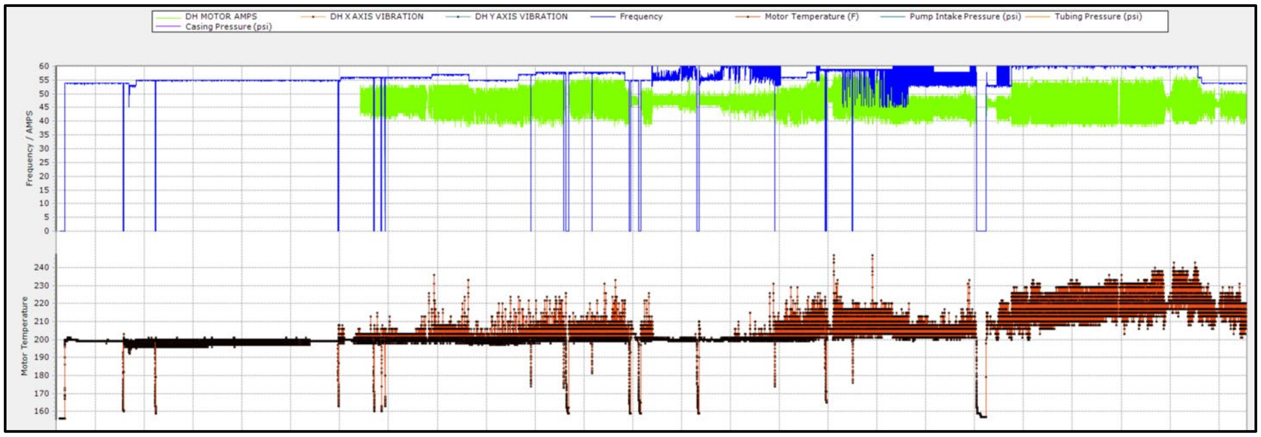


Figure 12: ESP Trends

Figure 12 shows the motor frequency, current and motor temperature of a ESP well.

After a typical ESP repair we normally have consistent drawdown and relatively stable motor current. But as the well continues to drawdown and fluid level decreases, and the well experiences periodic influxes of gas, seen with the motor temperature spikes in Figure 12. To mitigate this, the ESP is often set in PID or gas lock mode to help stabilize the motor current by automatically adjusting the frequency (fluctuating blue line, more narrow variation in the lime green). This process can be beneficial in some wells, but results vary.

As the well draws down, the above scenario can repeat often and decrease the integrity of ESP pump, eventually leading to its failure. As mentioned above, this is typically the time when operators should consider switching to a more efficient form of artificial lift.

b. Well 1

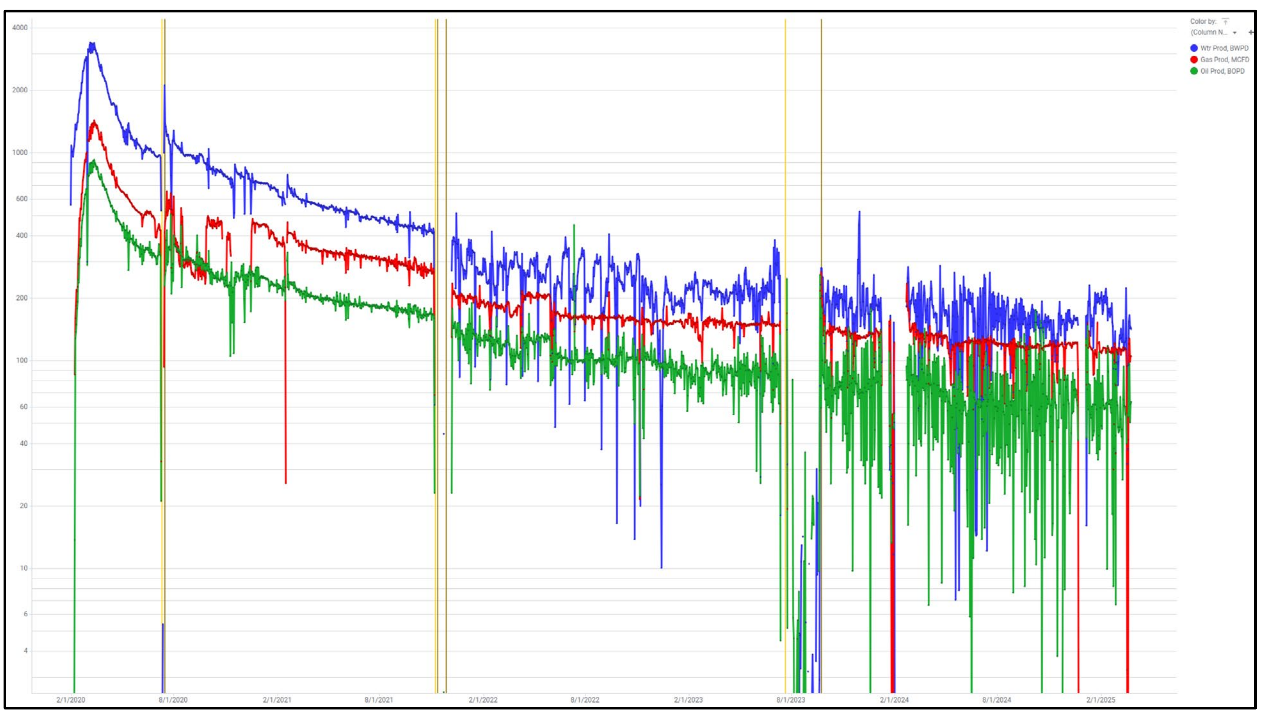


Figure 13: Well 1 - Production trends.

WORKOVERS

JOB_START	JOB_END	JOBTYP	JOBSUBTYP
7/20/2023	9/22/2023	MONITOR	OFFSET ACTI...
11/10/2021	11/25/2021	UPGRADE/INSTALL	ROD PUMP
11/6/2021	11/10/2021	SERVICE WELL	PULL DOWNH...
7/9/2020	7/14/2020	UPGRADE/INSTALL	ESP

Table 3: Workover for Well 1

Figure 13 shows a well's production from flowback to rod pump. After flowing pressure drops enough, artificial lift is needed and so in this case an ESP was installed. An increase in production is seen after the install but remains fairly close to decline curve trends. A little over a year the ESP failed and was repaired. When production declined enough and after another failure the well was converted to rod pump. In this case the rod pump did not fail but was pulled from some offset frac activity noted as "Monitor" for the JOBTYP. Production on rod pump has been stable and shows less of a decline that with ESPs.

c. Well 2

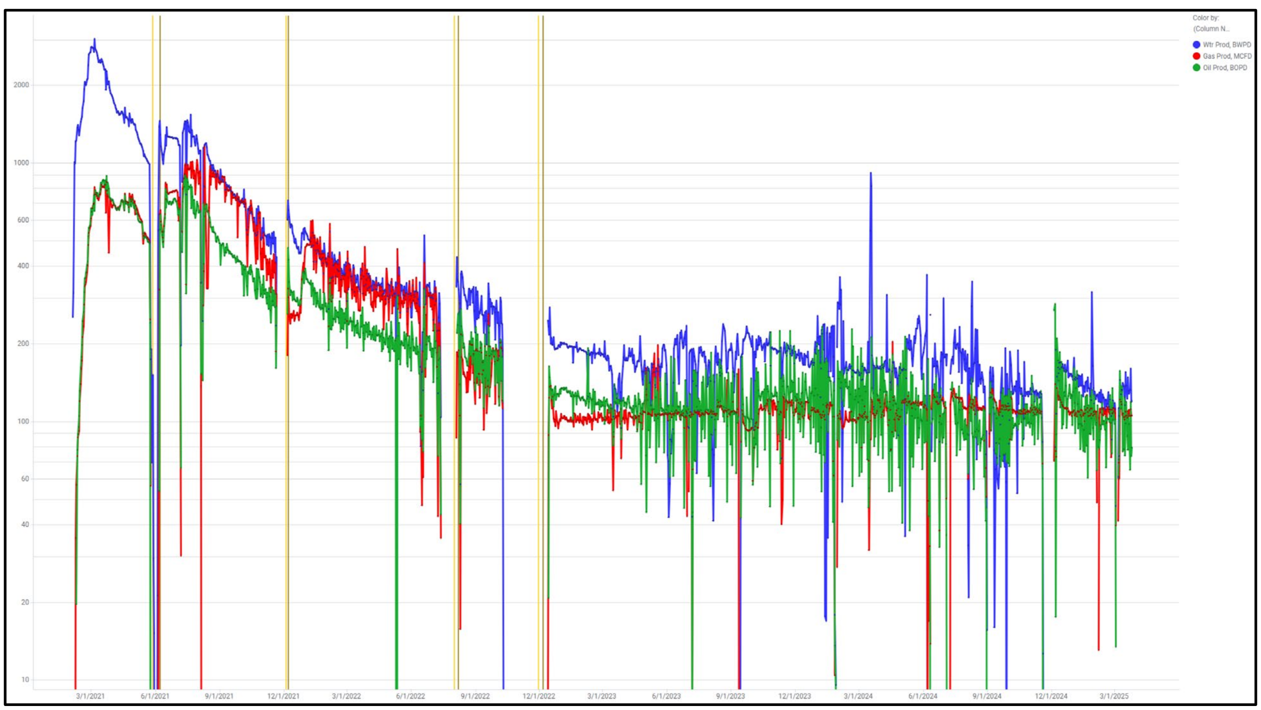


Figure 14: Well 2 Production Trend

WORKOVERS

JOB_START	JOB_END	JOBTYP	JOBSUBTYP
11/28/2022	12/5/2022	UPGRADE/INSTALL	ROD PUMP
7/31/2022	8/6/2022	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
12/3/2021	12/6/2021	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
5/26/2021	6/6/2021	UPGRADE/INSTALL	ESP

Table 4: Workover for Well 2

Figure 14 shows the production for Well 2. For this well an ESP was installed as a first form of lift. The first ESP failed after 6 months, from Table 4 and again 9 months later. The well was converted to rod pumps and hasn't failed since. Production is stable and shows no decline.

d. Well 3

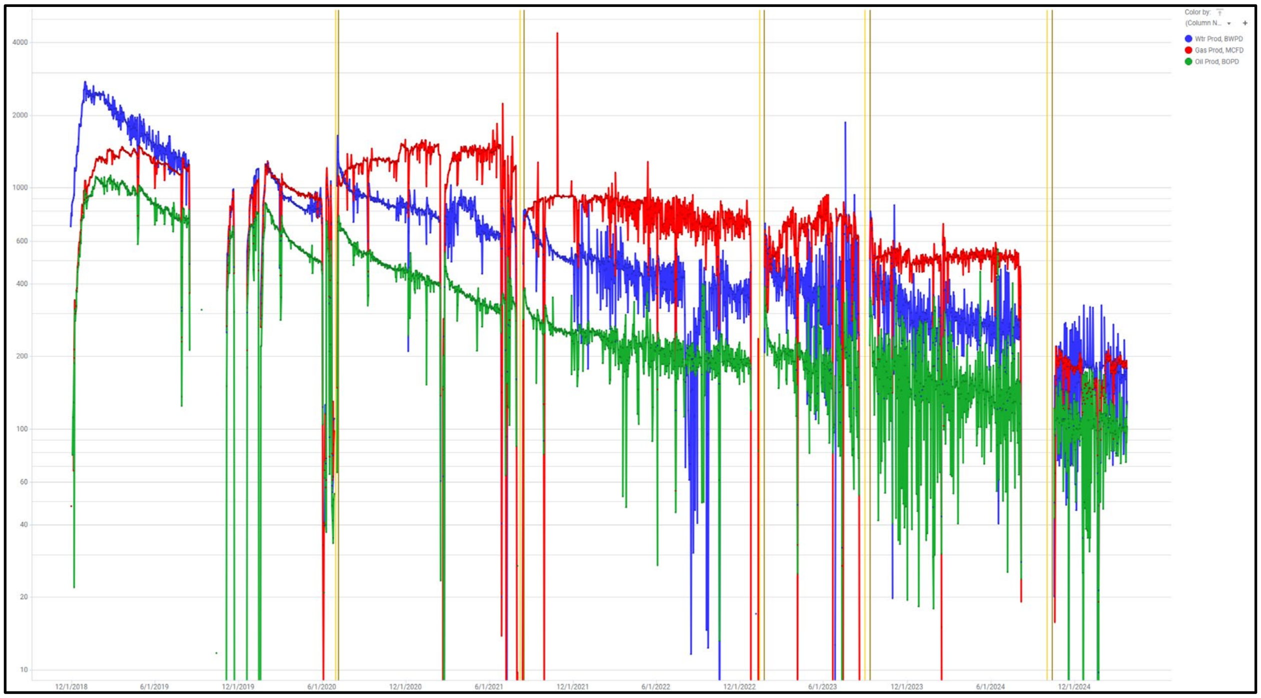


Figure 15: Well 3 – Production Trend

WORKOVERS

JOB_START	JOB_END	JOBTYP	JOBSUBTYP
9/30/2024	10/11/2024	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
8/29/2023	9/9/2023	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
1/11/2023	1/21/2023	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
8/5/2021	8/14/2021	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
6/28/2020	7/4/2020	UPGRADE/INSTALL	ESP

Table 5: Workover for Well 3

Figure 15 shows production trends for Well 3. In this well, ESPs were installed as a first type of artificial lift. In this well, the ESP system failed 4 times and was repaired before finally moving on to rod pump. The production on ESP follows a tempered decline, after conversion to rod pump, production is slightly less but seems more stable.

e. Well 4

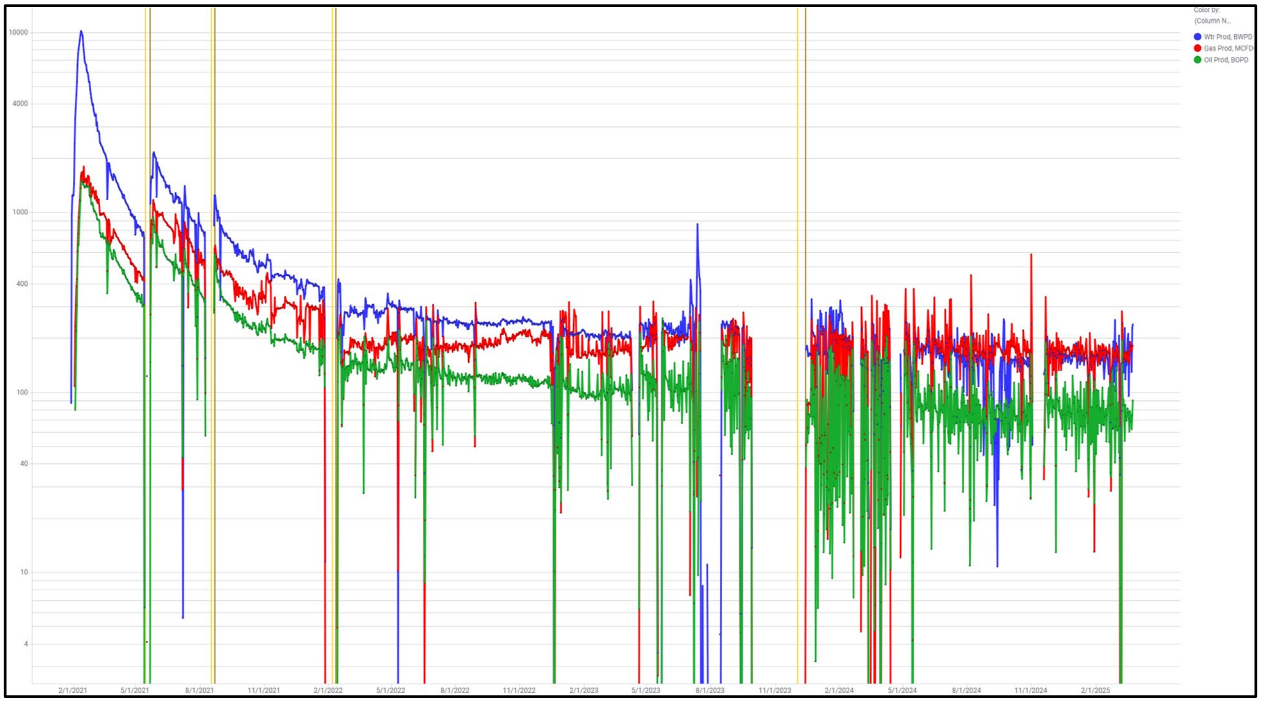


Figure 16: Well 4 – Production Trend

WORKOVERS

JOB_START	JOB_END	JOBTYP	JOBSUBTYP
12/1/2023	12/13/2023	RESTORE PROD-ROD PUMP	ROD REPAIR
2/5/2022	2/10/2022	UPGRADE/INSTALL	ROD PUMP
8/16/2021	8/21/2021	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
5/14/2021	5/20/2021	UPGRADE/INSTALL	ESP

Table 6: Workover for Well 4

For Well 4, the initial form of lift was ESPs. After one ESP failure and repair, the well was converted to rod pumps. The well has been on rod pumps since February 2022 with only one rod repair incident. As can be seen by Figure 1, the production trend is stable and does not show any significant decline.

f. Well 5

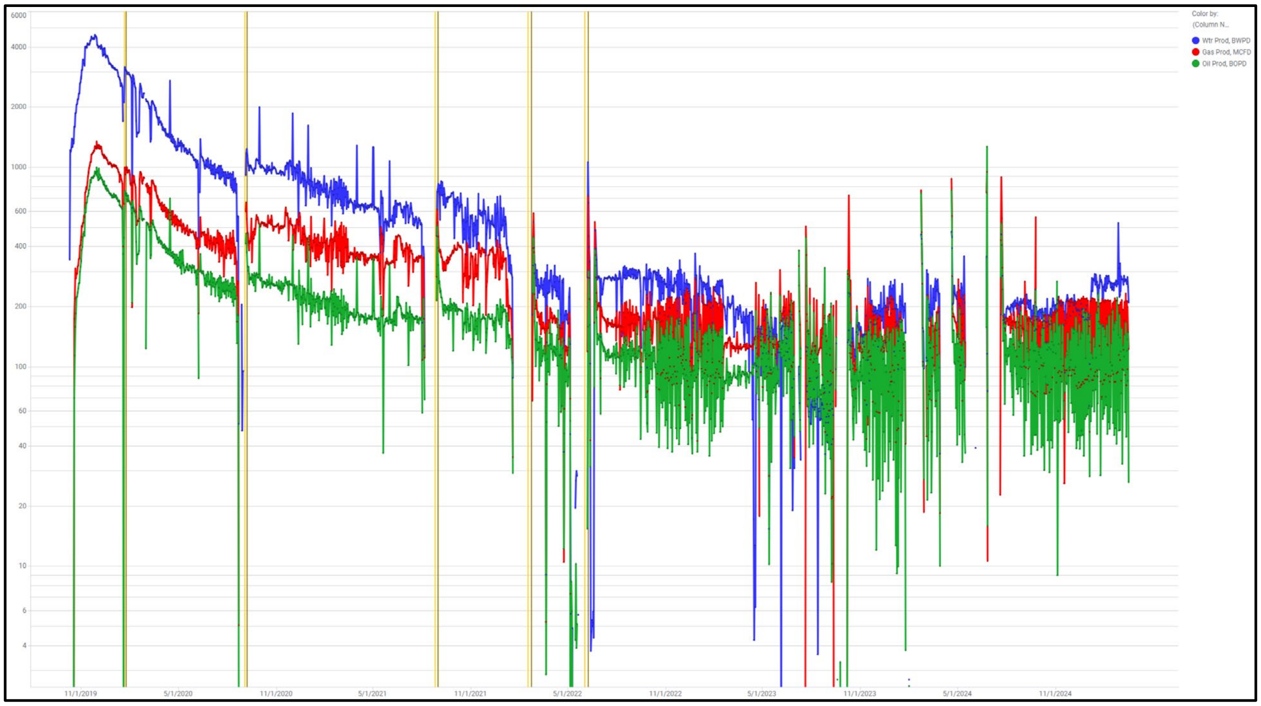


Figure 17: Well 5 Production Trend

WORKOVERS

JOB_START	JOB_END	JOBTYP	JOBSUBTYP
5/31/2022	6/7/2022	RESTORE PROD-ROD PUMP	TUBING REPAIR
2/14/2022	2/20/2022	UPGRADE/INSTALL	ROD PUMP
8/24/2021	8/29/2021	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
9/1/2020	9/5/2020	RESTORE PROD-ELECTRIC SUB ...	ESP REPAIR
1/19/2020	1/22/2020	UPGRADE/INSTALL	ESP

Table 7: Workover for Well 5

Figure 17 shows the production trend for Well 5. This is another case of ESP to rod conversion. After two failures and repairs of the ESP system, the well was converted to rod lift. The well has been on rod lift ever since with only one recorded tubing failure in three years. Also, it is important to note that the production trend shows stable production and no apparent decline.

CONCLUSION

This paper offers insight into what an operator should consider when planning the lifecycle of their installation. Often, operators keep ESP systems past the time where that form of lift is efficient for that well. Operators can save on OPEX and CAPEX by converting their wells to gas lift or rod pump without compromising overall production as seen from the results presented in this paper.

ACKNOWLEDGMENTS

The Liberty Lift team would like to thank Tommy Mazal and Devon Energy for their sponsorship and collaboration.

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