CONVERT TO ROD LIFT SOONER- LONG STROKE PUMPING UNITS

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Abstract

With the use of mechanical linear long stroke units, having stroke lengths of 288–416 inches, converting wells to rod lift is being done sooner. Rates of 400-900 barrels of fluid per day (BFPD) are being achieved in wells as deep as 10000 feet measured depth (MD). This helps to eliminate running multiple electric submersible pumps (ESP) to draw down a well into the 400-500 BFPD range.

This paper will discuss 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 real results about the wells highlighted in this document. This will also cover the technologies being utilized such as pumping unit selection, bottom hole assembly (BHA) and pump configurations, rod designs, and optimization with VSD Zone Control.

Introduction

The technology of linear long stroke 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 Texas[1]. 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 did not bode well with operators due to the lack of safety mechanisms on the units and limited qualified service/repair professionals to maintain units. However, the industry has since seen many improvements in both areas; safety features have been improved significantly, and the amount of trained service professionals has grown. The primary push for these linear long stoke units in our industry today is driven by higher production demands in horizonal well applications.

Stoke 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. This is where large conventional beam units and linear long stroke units start to become more common. The main take-away from the graph in figure 1, is that the demand for high volume rod lift has never been greater than it is today, and we continue to see this trend into the future.

In an effort to convert to rod lift sooner, operators have explored several options. The two main options being large conventional beam pumping units paired with fiberglass sucker rods and linear long strokes 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). 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. Running much slower than the conventional units (2.5-4.0 SPM), linear long stokes can achieve 400-700 BFPD depending on wellbore conditions. The benefit of utilizing this long and slow stroke allows the operator to optimize pump efficiency and extend downhole component life by reducing cycles on the system. This production range (400-700 BFPD) can represent a grey area for operators as seen in figure 2. Do they run another ESP or gas lift system knowing their run times or efficiencies could be compromised? Linear long stroke units present another alternative allowing operators to maintain production and/or system longevity.

So, why make this push to rod lift sooner instead of opting to run another ESP or gas lift system? ESPs commonly perform poorly in low volume lift applications, and they can present many challenges (300-500 BFPD range). Although, operators are converting to that 2nd or 3rd ESP above this volume range, it doesn't take long to draw the well down to a range where issues may be present. The main challenge here is high OPEX and CAPEX costs. There are high upfront costs with ESPs. The initial ESP can utilize a 450-475 HP motor, and the second ESP using a 300-350 HP motor, which can lead to high energy costs. Operators can save on energy costs with linear long stroke units; the highest horsepower requirement with these systems is 150 HP. Converting wells to rod lift can be expensive initially, however, one thing to consider is that the operator is converting the well to a form of lift that will last throughout the well's life.

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

General Design

Linear long Stroke Pumping units have had significant advancements in their technology since initial inception. With the integration of new safety features and the increase of structural capacity and stroke lengths, the capability to increase fluid production, via a rod lift system, has expanded considerably. These units have a variety of stroke lengths from 288 inches to 416 inches, with structural ratings reaching up to 60,000 pounds (Refer to Table 1). It should be noted that most high-volume applications, require these units to stroke at faster speeds. This necessitates the installation of a VSD to achieve these higher speeds due to inherent mechanical characteristics of the units.

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, 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. Conversely, with a unit featuring a higher structural capacity of 55,000 pounds and a stroke length of 416 inches, production rates exceeding 650 BFPD can be achieved at depths nearing 9000 feet, depending on wellbore conditions. This scenario requires greater horsepower than smaller long stroke units and can require the utilization of tubing pumps in a 2-7/8-inch tubing application.

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. With this data, consideration must also be given to the primary goal. Is the objective 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.

Once the goal is outlined and a design is being finalized it is crucial to carefully select the down hole equipment: BHA, gas separator, and downhole pump design. Inadequately sized BHA and downhole pump configurations can significantly limit high-volume production and cause premature system failures. Table 2 displays the typical downhole pump lengths and bore diameters with corresponding base level constraints.

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 dyno 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.

Case studies

Case Study #1 – 320-550-416 (Lea County, NM)

This operator struggled to keep ESP’s running due to solids and gas interference. The operator elected to run a 416 inch long stroke unit at a faster speed (4.5SPM) in order to maintain a high production rate. The target production for this well was 800+ BFPD and had a pump intake pressure (PIP) over 1600psi. The well had 5.5” production casing with 2-7/8” production tubing. It was converted to rod lift using a 320-550-416 unit, High Strength Rods (86 Taper) with 1.625” sinker bar, a 2.25” tubing pump and packer style BHA for the initial installation. The pump was set at 9000ft Measured Depth (MD). Side loads near surface were over 500lbs and less severe downhole. In the first month, an average of 850 BFPD was achieved with the pumping unit stroking at 4.5 SPM. This well produced steadily for three months before a sucker rod failure (operator was pleased with this performance because of the high initial production rates). The failure occurred near the top of the ¾” sucker rod taper. The operator decided to reduce the length of the ¾” taper, extend the 7/8” taper and slow the unit down to 3.8-4.0SPM. The well continued to produce over 500 BFPD and the failure rate was reduced.

Case Study #2 –320-550-416 (Lea County, NM)

This operator’s goal was to eliminate the need to run a 3rd Electric Submersible Pump (ESP) and maintain a production goal of 450-500 BFPD with a PIP at 400-450psi. The well had 5.5” production casing with 2-7/8” production tubing. It was converted to rod lift using a 320-550-416 unit, High Strength Rods (878 Taper) with 1.00” sinker rods, a 1.75” insert pump and packer style BHA. The pump was set at 10,150ft MD. Sideloads peaked at 375-400lbs near surface and the well maintained a 6-degree tangent to 9000ft MD. In the first month, an average of 465 BFPD was achieved with the unit stroking at 3.7SPM. In the first four months the system maintained an average of 450 BFPD.

Case Study #3 – 320-550-416 (Winkler County, TX)

This operator’s goal was installing a rod lift system after the first ESP failed, maintain steady production, and focus on longevity of the downhole components. The pump was set at 8950ft, 1300ft above the Kickoff Point (KOP). For this design, the production goal was 500+ BFPD with a PIP at 600psi. The well had 5.5” production casing with 2-7/8” production tubing. It was converted to rod lift using a 320-550-416 unit, High Strength Rods (86 Taper) with 1.625” sinker bar, a 2.25” tubing pump and packer style BHA. Sideloads peaked at 250-300lbs near surface and deviation was minimal throughout the well. In the first month, an average of 500 BFPD was achieved with the unit stroking at 2.6SPM. This well continued to maintain an average production rate of 350-450 BFPD for over 2.5 years before its first intervention. Post intervention, the pump was lowered to 10,200ft (landed at the KOP).

Case Study #4 – 320-500-366 (Yoakum County, TX)

This operator had an ESP landed in a 45-degree tangent section with the ESP intake at 5380’ MD. The goal was to replace the ESP and land the intake of the rod pump as close to the original intake depth, while still maintaining production with a low PIP (230psi). Before the ESP failure, the well produced an average of 350-375 BFPD, but the rod lift production goal was 400+ BFPD. The well had 5.5” production casing with 2-7/8” production tubing. It was converted to rod lift using a 320-500-366 unit, KD sucker rods (88 Taper) with 1.50” sinker bar above the KOP and 1” guided rod below the KOP. A 2.00” insert pump and packer style BHA was used. Sideloads were 225-250lbs near surface, but over 300lbs at the KOP and above the pump set depth. Since the pump was set below the KOP and at a 45-degree inclination, sinker bar was used above the KOP to keep the upper 1” sucker rod taper in tension. In the first month an average of 400+ BFPD was achieved with the unit stroking 3.6 SPM. The well settled out producing a constant 250-300 BFPD throughout the next 10 months after install.

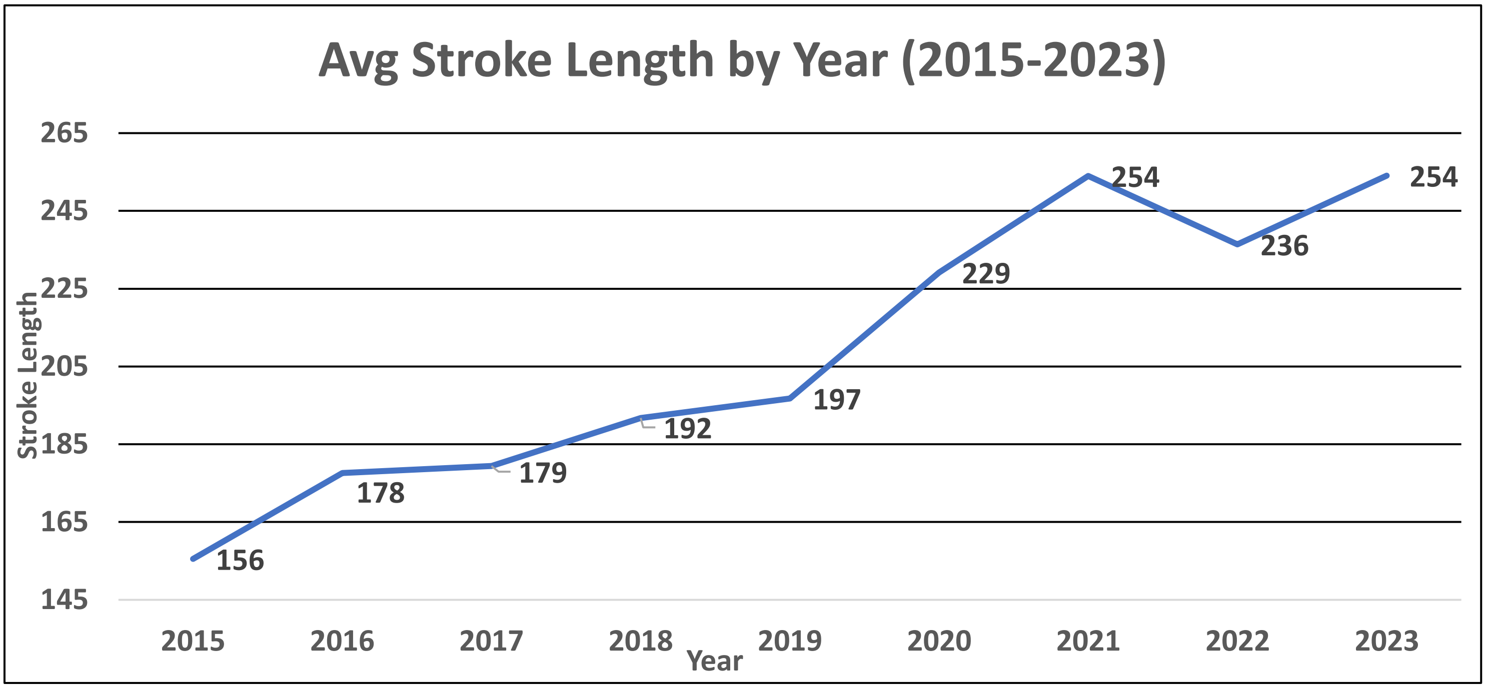
Conclusion

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 max volumes or increase system longevity, based on their goal for the system.

References

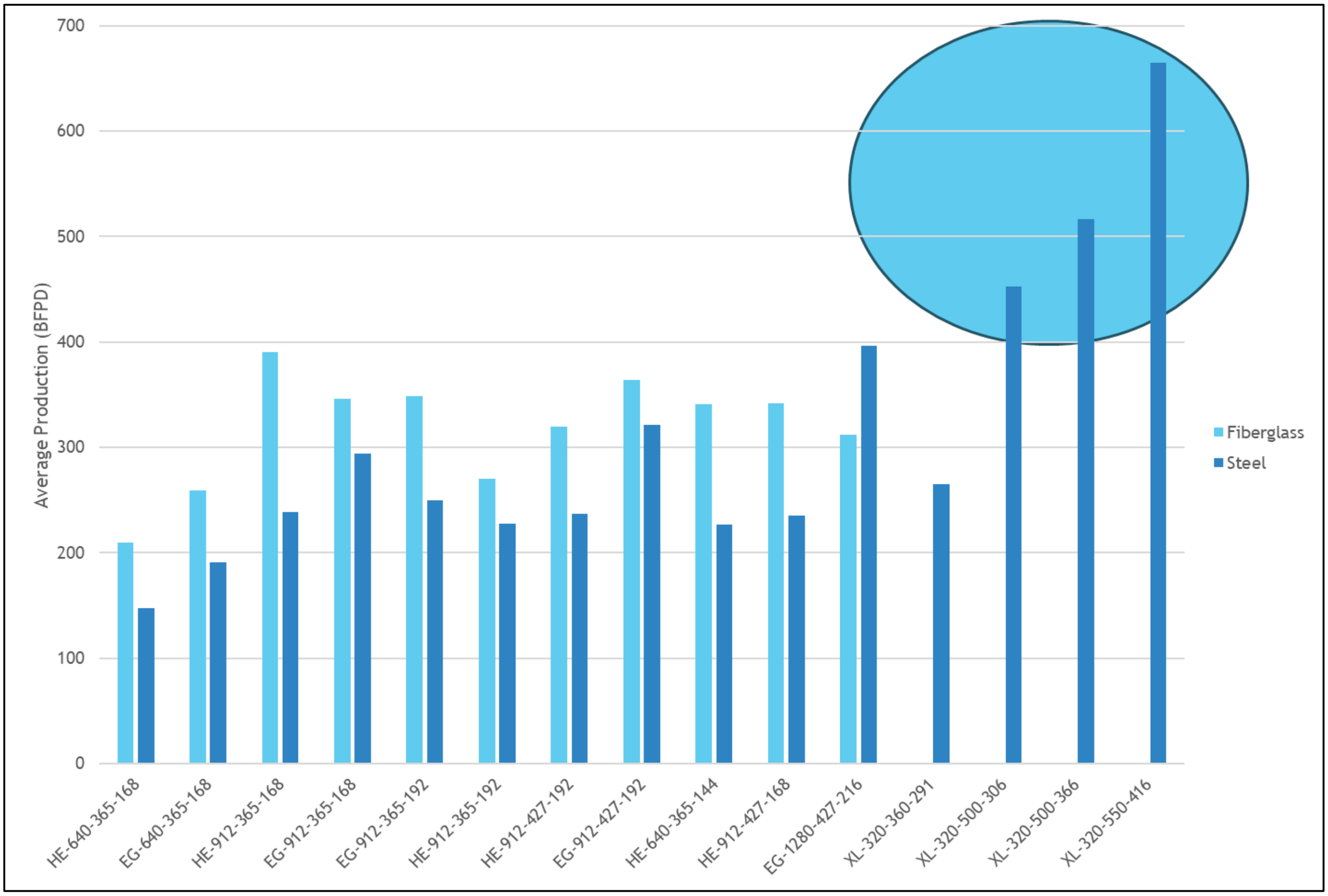
1. Lang, Jerry M, and Gordon R Lively. *Well Pumping Unit with Counterweight*. 19 Jan. 1988.

Figure 1. Stroke Length Trends 2015-2023



Data is the average stroke length pumping unit installed by Liberty Lift Solutions in the given year. This shows an increasing trend for longer stroke lengths over an eight-year period. Increasing by an average of 98 inches from 2015 to 2023.

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



Data is based on 160 rod designs performed by Liberty Lift Solutions, of which 130 were installed. The dark blue bars represent production averages using an all steel sucker rod string for each unit size. The light blue bars represent production averages using a fiberglass/steel sucker rod string for each unit size. The blue circle highlights the average production ranges that linear long stroke units are capable of.

* Data collected within the last 18 months

Table 1. Typical Linear Long-Stroke Pumping Unit Specifications

Reducer (lbs)	Structure (lbs)	Stroke Length (in)	Max SPM Range w/ VSD*	Max Production Range** (~5,000)	Max Production Range** (~9,000')
250,000	30,000	288	4.75-5.25	500	NA***
320,000	36,000	291	4.75-5.25	500	NA***
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 displays the technical specifications for the six most common linear long stroke units available in the current North American market. Also highlighted is the max production rate by unit by depth.

*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 2. Operations

Unit Stroke Length	291"	306"	366"	416"
Max Insert Pump Diameter	2"	2"	2"	1.75"
Tubing Pump Diameter	2.25" or greater	2.25" or greater	2.25" or greater	2" or greater
Pump Length	36’	40’	42’ (caveat for the 2”)	47’
Polished Rod Length	36'	40'	46'	50'

Table displays the API pump length, type, and bore size that is 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

Case Study #1: Lea County XL 320-550-416

Rod design for Case Study #1

INPUT DATA

Strokes per minute:	4.2	Pump int. pr. (psi):	1632
Run time (hrs/day):	24.0	Fluid level (ft over pump):	4259
Tubing pres. (psi):	50	Stuf.box fr. (lbs):	100
Casing pres. (psi):	50	Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	90%
Water sp. gravity:	1
Oil API gravity:	35.0
Fluid sp. gravity:	0.985

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D
Size:	150 hp

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):	9000	Tub.anch.depth (ft):	9000
Pump conditions:	Full		
Pump type:	Tubing	Pump vol. efficiency:	85%
Plunger size (in):	2.25	Pump friction (lbs):	0.0

CALCULATED RESULTS

Production rate (bfpd):	857	Peak pol. pod load (lbs):	38386
Oil production (BOPD):	86	Min. pol. rod load (lbs):	12010
Strokes per minute:	4.2	MPRL/PPRL:	0.313
System eff. (Motor->Pump):	37%	Unit struct. loading:	70%
Permissible load HP:	171.1	PRHP / PLHP:	0.41
Fluid load on pump (lbs):	9022	Buoyant rod weight (lbs):	18847
Fluid level tvd (ft from surface):	4739	N/No: .162 , Fo/SKr: .13	
Polished rod HP:	69.7		

Prime Mover Speed Variation
Speed variation not considered

Motor Loading: 67%

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	221
Gearbox loading:	69.1%
Cyclic load factor:	1.042
Counterbalance weight(M lbs):	25.2
Daily electr.use (Kwh/Day):	1430
Monthly electric bill:	$2617
Electr.cost per bbl fluid:	$0.100
Electr.cost per bbl oil:	$1.001

Tubing, Pump And Plunger Calculations

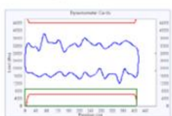
Tubing stretch (in):	.0
Prod. loss due to tubing stretch (bfpd):	0.0
Gross pump stroke (in):	407.0
Pump spacing (in. from bottom):	43.9
Minimum pump length (ft):	48.0
Recommended plunger length (ft):	6.0

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

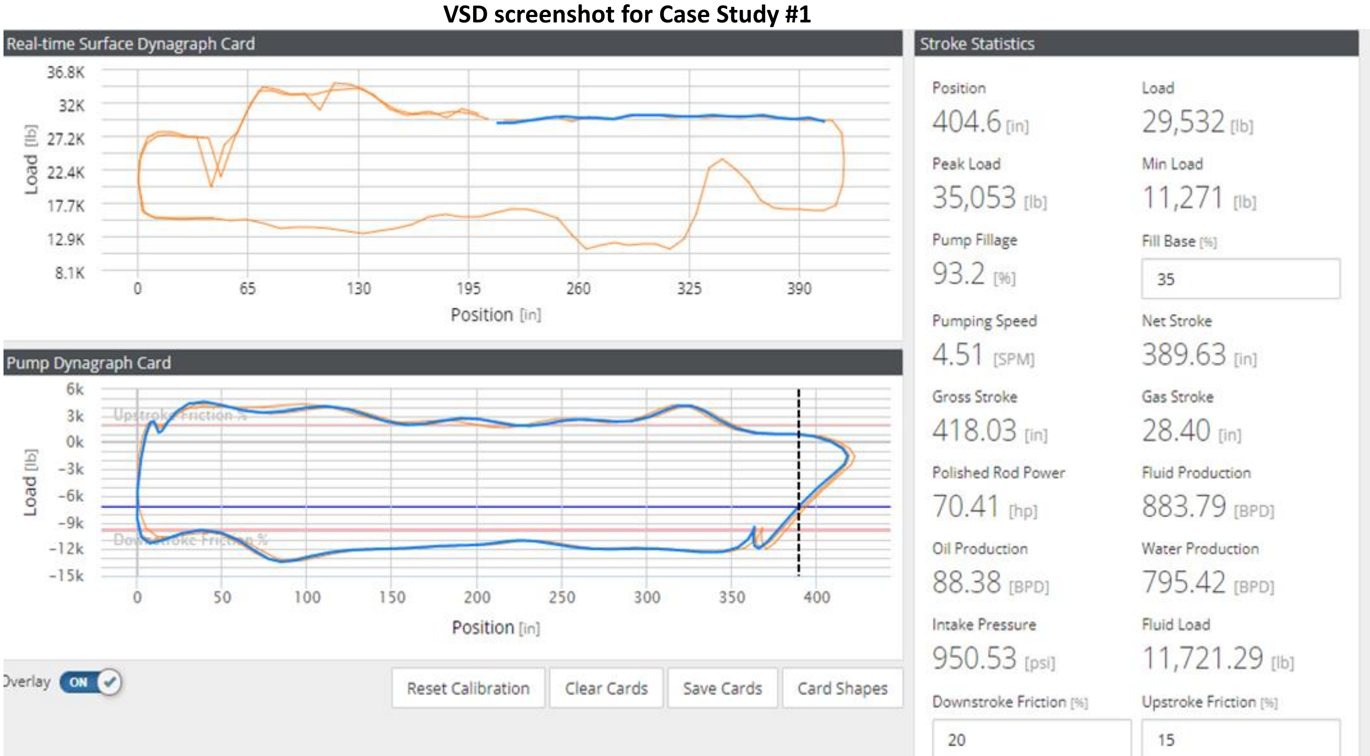
Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1	LL HS	400	140000	0.2	82.6%	48747	15418	13991	0
+ 1	LL HS	1325	140000	0.25	79.0%	46531	13854	13301	4
0.875	LL HS	500	140000	0.25	78.5%	47873	16961	16713	4
0.875	LL HS	2375	140000	0.2	70.9%	44447	16124	10104	0
0.875	LL HS	550	140000	0.25	57.3%	34375	8928	8184	4
0.875	LL HS	700	140000	0.25	54.6%	31839	6872	6409	4
0.75	LL HS	300	140000	0.25	74.6%	41276	7461	7110	4
0.75	LL HS	1850	140000	0.2	73.1%	39556	5550	1185	0
0.75	LL HS	500	140000	0.25	64.3%	31655	-832	587	4
@ 1.625	Flexbar C	500	90000	0.2	73.8%	16011	-874	0	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).



VSD screenshot for Case Study #1



Case Study #2: Lea County XL320-550-416

Rod design for Case Study #2

INPUT DATA

Strokes per minute:	3.9	Pump int. pr. (psi):	410
Run time (hrs/day):	24.0	Fluid level (ft over pump):	921
Tubing pres. (psi):	180	Stuf.box fr. (lbs):	100
Casing pres. (psi):	70	Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	79%
Water sp. gravity:	1.09
Oil API gravity:	42.0
Fluid sp. gravity:	1.0324

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):	10150	Tub.anch.depth (ft):	10150
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	1.75	Pump friction (lbs):	200.0

CALCULATED RESULTS

Production rate (bfpd):	465	Peak pol. rod load (lbs):	43275
Oil production (BOPD):	98	Min. pol. rod load (lbs):	13717
Strokes per minute:	3.9	MPRL/PPRL:	0.317
System eff. (Motor->Pump):	33%	Unit struct. loading:	79%
Permissible load HP:	158.9	PRHP / PLHP:	0.50
Fluid load on pump (lbs):	10342	Buoyant rod weight (lbs):	21353
Fluid level tvd (ft from surface):	9179	N/No: .16 ,	Fo/SKr: .151
Polished rod HP:	79.6		

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

NEMA D motor:	125 HP
Single/double cyl. engine:	100 HP
Multicylinder Engine:	125 HP

Torque analysis and electricity consumption BALANCED (Min Torq)

Peak g'box torq.(M in-lbs):	248
Gearbox loading:	77.5%
Cyclic load factor:	1.054
Counterbalance weight(M lbs):	28.5
Daily electr.use (Kwh/Day):	1749
Monthly electric bill:	$3201
Electr.cost per bbl fluid:	$0.226
Electr.cost per bbl oil:	$1.074

Tubing, Pump And Plunger Calculations

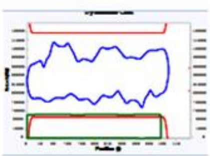
Tubing stretch (in):	.0
Prod. loss due to tubing stretch (bfpd):	0.0
Gross pump stroke (in):	393.2
Pump spacing (in. from bottom):	47.9
Minimum pump length (ft):	47.0
Recommended plunger length (ft):	6.0

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	LL HS	1400	140000	0.2	95.8%	54972	17592	14505	0
+ 1	LL HS	925	140000	0.25	82.4%	48019	14029	13092	4
0.875	LL HS	6325	140000	0.25	98.8%	55727	16543	443	4
+ 1	LL HS	1500	140000	0.25	38.6%	18196	-1456	-255	4

+requires slimhole couplings.

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



VSD screenshot for Case Study #2

No Malfunction

Running, Fillage

Well State Elapsed Time	Remaining Down Time
1 day 09 : 11 : 17	N/A

Start Stop

Equipment Loading

		Current
Gearbox Loading (%)		N/A
Structure Loading (%)		130
	Rod Number	%
Highest Loaded Rod Taper	1	87

Operational Status

	Today	Yesterday
Cycles (c/day)	0	0
Run Time (hh:mm:ss)	20 : 38 : 25	24 : 00 : 00
Peak Load (lbs)	39900	39900
Minimum Load (lbs)	14790	14900
Pumping Unit Speed (avg)	3.7	3.7

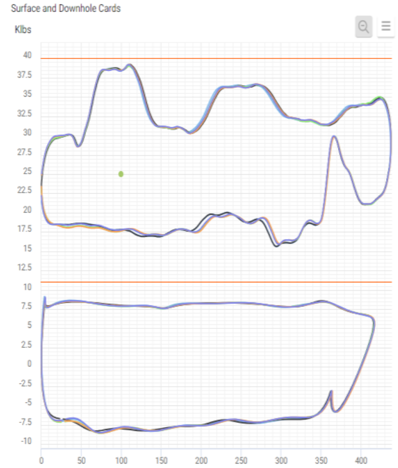
	Current
Pumping Unit Speed (SPM)	3.7
Fluid Load (lbs)	14130
Last Stroke Peak Load (lbs)	39553
Last Stroke Min Load (lbs)	15601

Production Status

	Today	Yesterday
Oil (bbl/day)	120	144.4
Gas (mcfd)	18	21.6
Water (bbl/day)	254.9	306.9
Total Fluid (bbl/day)	374.9	451.3

	Current
Instantaneous (bbl/day)	459.1
Pump Leakage (bbl/day)	32.5
Pump Fillage (%)	93

Surface and Downhole Cards



Auto Update

Show Set Points

Last 5 cards 1 2 3 4 5 - Latest All

Case Study #3: Winkler County XL 320-550-416

Rod design for Case Study #2

INPUT DATA				CALCULATED RESULTS			
Strokes per minute:	2.8	Pump int. pr. (psi):	600	Production rate (bfpd):	505	Peak pol. pod load (lbs):	42312
Run time (hrs/day):	24.0	Fluid level (ft over pump):	1516	Oil production (BOPD):	152	Min. pol. rod load (lbs):	15080
Tubing pres. (psi):	50	Stuf.box fr. (lbs):	100	Strokes per minute:	2.8	MPRL/PPRL:	0.356
Casing pres. (psi):	50	Pol. rod. diam.	1.5"	System eff. (Motor->Pump):	43%	Unit struct. loading:	77%
				Permissible load HP:	114.1	PRHP / PLHP:	0.47
				Fluid load on pump (lbs):	12851	Buoyant rod weight (lbs):	20020
				Fluid level tvd (ft from surface):	7429	N/No: .108 , Fo/SKr: .175	
				Polished rod HP:	53.4		
				Required prime mover size (speed var. not included)		BALANCED (Min Torq)	

Fluid Properties		Motor & Power Meter	
Water cut:	70%	Power meter	Detent
Water sp. gravity:	1.04	Elect. cost:	$.06/KWH
Oil API gravity:	42.0	Type:	NEMA D
Fluid sp. gravity:	0.9727		

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

Pumping Unit: Liberty LiftSolutions (XL 320-550-416)	
API Size: R-320-550-416 (Unit ID CUSTOM)	
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

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq. (M in-lbs):	228
Gearbox loading:	71.4%
Cyclic load factor:	1.073
Counterbalance weight (M lbs):	28.7
Daily electr. use (Kwh/Day):	1132
Monthly electric bill:	$2071
Electr. cost per bbl fluid:	$0.134
Electr. cost per bbl oil:	$0.448

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):	8950	Tub.anch.depth (ft):	8950
Pump conditions:	Full		
Pump type:	Tubing	Pump vol. efficiency:	85%
Plunger size (in):	2.25	Pump friction (lbs):	200.0

Tubing, Pump And Plunger Calculations	
Tubing stretch (in):	.0
Prod. loss due to tubing stretch (bfpd):	0.0
Gross pump stroke (in):	359.8
Pump spacing (in. from bottom):	26.9
Minimum pump length (ft):	47.0
Recommended plunger length (ft):	6.0

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

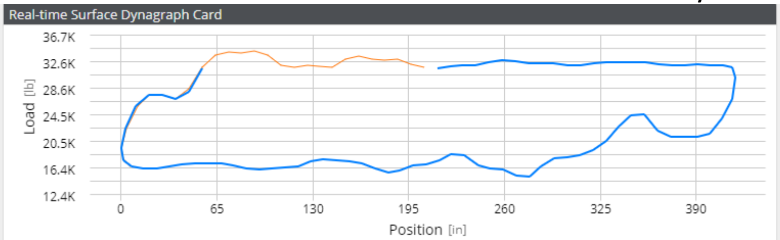
Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1	LL HS	800	140000	0.2	90.8%	53747	19327	16685	0
+ 1	LL HS	1700	140000	0.25	83.8%	49750	16452	13455	4
0.875	LL HS	2500	140000	0.25	91.0%	52879	17069	11168	4
0.875	LL HS	1350	140000	0.2	68.3%	39827	9909	7521	0
0.75	LL HS	2000	140000	0.2	89.4%	48719	9064	4453	0
@ 1.625	C (API. SB)	600	90000	0.2	90.6%	21202	1336	-96	0

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

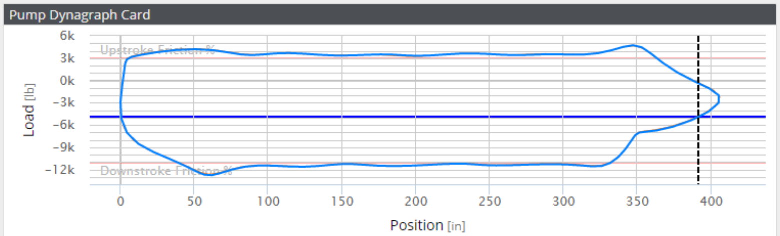
NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).

VSD screenshot for Case Study #3

Real-time Surface Dynagraph Card



Pump Dynagraph Card



Overlay ON

Reset Calibration | Clear Cards | Save Cards | Card Shapes

Stroke Statistics

Position 54.8 [in]	Load 31,644 [lb]
Peak Load 34,404 [lb]	Min Load 15,036 [lb]
Pump Fillage 96.6 [%]	Fill Base [%] 45
Pumping Speed 2.57 [SPM]	Net Stroke 391.29 [in]
Gross Stroke 405.07 [in]	Gas Stroke 13.76 [in]
Polished Rod Power 37.65 [hp]	Fluid Production 504.82 [BPD]
Oil Production 126.21 [BPD]	Water Production 378.62 [BPD]
Intake Pressure 413.53 [psi]	Fluid Load 14,011.05 [lb]
Downstroke Friction [%] 10	Upstroke Friction [%] 10

Case Study #4: Yoakum County XL 320-500-366

Rod design for Case Study #2

INPUT DATA

Strokes per minute: 3.6
Run time (hrs/day): 24.0
Tubing pres. (psi): 50
Casing pres. (psi): 50

Pump int. pr. (psi): 230
Fluid level (ft over pump): 449
Stuf.box fr. (lbs): 100

Pol. rod. diam. 1.5"

Fluid Properties

Water cut: 85%
Water sp. gravity: 1
Oil API gravity: 35.0
Fluid sp. gravity: 0.9775

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
Tubing I.D. (in): 2.441

Upstr. rod-fl. damp. coeff.: 0.100
Dnstr. rod-fl. damp. coeff.: 0.100

Pump depth (ft): 5300
Pump conditions: Full
Pump type: Insert
Plunger size (in): 2

Tub.anch.depth (ft): 5300
Pump vol. efficiency: 80%
Pump friction (lbs): 200.0

CALCULATED RESULTS

Production rate (bfpd): 479
Oil production (BOPD): 72
Strokes per minute: 3.55
System eff. (Motor->Pump): 33%
Permissible load HP: 126.8
Fluid load on pump (lbs): 6483
Fluid level tvd (ft from surface): 4830
Polished rod HP: 42.1

Peak pol. rod load (lbs): 31165
Min. pol. rod load (lbs): 8972
MPRL/PPRL: 0.288
Unit struct. loading: 62%
PRHP / PLHP: 0.33
Buoyant rod weight (lbs): 15510
N/No: .079 , Fo/SKr: .043

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

NEMA D motor: 60 HP
Single/double cyl. engine: 50 HP
Multicylinder Engine: 60 HP

Torque analysis and electricity consumption

BALANCED (Min Torq)

Peak g'box torq.(M in-lbs): 186
Gearbox loading: 58.2%
Cyclic load factor: 1.045
Counterbalance weight(M lbs): 20.07

Daily electr.use (Kwh/Day): 904
Monthly electric bill: $1654
Electr.cost per bbl fluid: $0.113
Electr.cost per bbl oil: $0.755

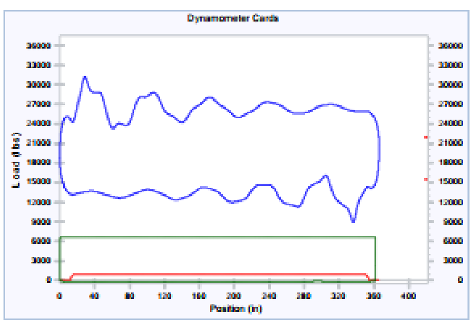
Tubing, Pump And Plunger Calculations

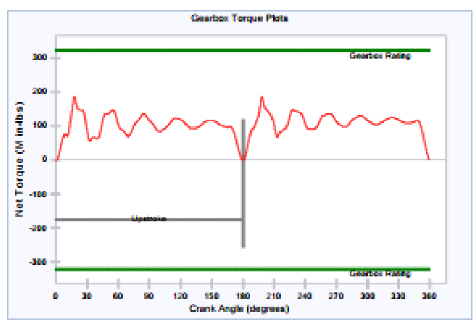
Tubing stretch (in): .0
Prod. loss due to tubing stretch (bfpd): 0.0
Gross pump stroke (in): 361.7
Pump spacing (in. from bottom): 31.9
Minimum pump length (ft): 39.0
Recommended plunger length (ft): 4.0

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	LL KD T/2.8	3750	125000	0.25	74.8%	39553	11551	2545	4
@ 1.5	C (API. SB)	800	90000	0.2	86.2%	20383	1589	-493	0
+ 1	LL KD T/2.8	750	125000	0.25	30.3%	11713	-2261	-255	4

+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).
NOTE: Sinker bars should not be placed where the inclination is more than 4 degrees.





VSD screenshot for Case Study #3