UNCONVENTIONAL RESULTS WITH CONVENTIONAL LONG STROKE ROD LIFT SYSTEMS: A STUDY OF DESIGN PROCESS AND RESULTS PRODUCED IN VARIOUS APPLICATIONS

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ABSTRACT

Sucker rod pumping is largely regarded as the final artificial lift method in a well's lifecycle. Until now, the industry standard application of sucker rod pumping systems has been up to 400 barrels per day fluid production. In the natural progression of continuous improvement and technology development, our industry must constantly question and challenge the approach of "what has been done" as compared to "what is needed." With the industry advancing towards deeper wells and increasingly aggressive production targets, the challenge of meeting these application parameters while decreasing costs has become forefront to an operator's requirements for profitability and in some cases, survival. To meet this need, a system design comprised of a novel conventional 2560-500-320 pumping unit and fit-for-purpose rod string and pump, coupled with the ability to accurately control performance with automation was established. Through a comprehensive design analysis which factors in well characteristics, operational preferences, and production requirements, a process was developed to optimize production while minimizing lifting costs for operators. This approach has proven to lower or eliminate capital and operating costs for oil and gas producers by reducing the number or types of artificial lift methods, increasing fluid production, reducing failures, and lowering workover costs, as compared to other artificial lift methods or different pumping unit types. This paper will review design objectives, challenges, predictive analytics, implementation, economics, and the application results ranging from 400 to over 1000 barrels per day of fluid production achieved.

PROBLEM STATEMENT

Converting forms of artificial lift is a decision made based on a myriad of factors, including the price of oil and gas, cost of artificial lift systems, production decline, projected production with each system, asset value, depreciation, and so on. The decision is also impacted by which artificial lift method is currently utilized and which method the well will be converted to. For example, gas lift is heavily impacted by the price of gas, as there is an economic threshold where purchasing gas for injection is no longer profitable. Conversely, the rise in crude oil price opens a lot of opportunity for projects because the value of that which is produced has risen. Electronic submersible pumps (ESPs) are a great example of this. They are relatively expensive considering their run times, but they can move large amounts of fluid. While an ESP offers advantages within the scope of artificial lift systems, the benefits can be burdened by the cost of frequent failures. Such recurrent failures are especially problematic when factoring in workover costs and associated deferred production during these downtimes. As such, other artificial lift methods are typically reviewed for greatest economic benefit weighed against the factors of time, value, and return on investment. One of these options has historically been a sucker rod pump or rod lift system.

When a sucker rod pump (SRP) system is considered for artificial lift conversion, some of the key points evaluated are production volumes and associated challenges related to timing of installation. Typically, there is a noticeable dip in daily production when converting from ESPs to SRPs. SRPs are largely regarded to have a maximum production range of 400 barrels of fluid per day (bfpd). Therefore, they are often utilized as the final artificial lift method once the well's production has tapered down the IPR curve. Rod lift systems with long stroke lengths have been one solution to increasing production capabilities of

SRP, and therefore decreasing the production loss associated with ESP to SRP artificial lift conversion. Although the current long stroke tower-style (or belt-driven) pumping unit offerings on the market don't quite match the ESP's production, they are an improvement over pumping units with less than 250 inches (in) of stroke. This increased production from a longer stroke is a benefit, but it poses a different issue in that the tower-style unit only has one stroke length, and this lack of flexibility is not always suitable throughout the life of the well. Despite this limitation, tower-style pumping units have been widely adopted. As such, [SSH3]it has become a common practice for operators to partake in the "unit shuffle," and exchange tower-style units throughout their fields with smaller-stroked beam geometry pumping units to better meet the need of lower production values. This can create more challenges due to the operational expenses of tower unit removal, base changes, smaller beam unit installation, tower unit transport to a new well, new base installation, and then reinstalling the tower unit. Additionally, moving assets can depreciate the value depending on the accounting method observed.

To meet these existing challenges within artificial lift programs,Lufkin Industries brought to market an alternative method for producing large amounts of fluid by coupling the benefits of long stroke SRP system with the versatility of a conventional beam-style pumping unit. This project was initiated with the intention of giving oil and gas operators a method of producing large volumes of fluid while maintaining the flexibility of multiple stroke lengths, so that they may draw down wells over time without requiring depreciative asset transfers.

BACKGROUND

Conventional Long Stroke Pumping Unit Technology

When considering SRP units, there is a variety of geometries available to the market, including, but not limited to: class I and class III crank-balanced geometries, class I beam-balanced, tower or belt-driven, low profile, linear, hydraulic, and class III air-balanced. The industry continues to find ways to actuate the down hole pump with new surface technologies.

The C2560-500-320 is a class I, crank-balanced, conventional, beam-style pumping unit. This nomenclature denotes 2,560,000 inch-pound (in-lb) gear box torque, 50,000 lb structural rating, and 320 in stroke length (Figure 1, Table 1). The crank arms feature four crank holes enabling the unit to have four stroke lengths of 320 in, 275 in, 234 in, and 193 in. The unit can pump between 1-6.5 strokes per minute (spm).

All of the conventional long stroke unit's components meet or exceed the standards set forth in API 11E. It has roller bearings throughout the design, including the gearbox. The gear reducer has hobbed-cut gears for consistent manufacturing and a quieter start-up. The double helical gears feature a center relief where each side mates with a single helical gear to ensure a symmetrical load path and proper load transference. It features a troughed oil lubrication system and wipers. The gearbox is driven by a 150 horsepower (hp) NEMA B 8-pole motor and controlled with a 150 hp LWM 2.0 variable speed drive (VSD). This automation allows precise operation and accurate, real-time monitoring of the well and SRP system.

The unit has integral crank pin sleeves and factory-pressed crank arms weighing 9,947 lb supporting 14,500 lb counterweights (Table 1). It employs multi-jack bolt tensioners, commercially known as SR nuts,Superbolts, and Supernuts, throughout to ensure proper torque and reliable seating (Figure 2). Their application completely removes the need for hammer wrenches in installation and maintenance of this unit.

The technology has been quickly adopted by the industry, installing more than 20 units across the country with runtimes over a year and a half.

Design Process

When approaching artificial lift conversion, engineers model different options in predictive analytical software to assist in determining which artificial lift method to choose and when to implement. To begin the design process, one must consider the goals associated with the operating company and the capability of each well individually. Goals for artificial lift design include production targets, total cost of ownership, operational initiatives, or mitigation of any debris or undesirable elements in the fluid. These goals are considered in conjunction with well characteristics like deviation and fluid properties. Company specific factors such as frequent failures and equipment preferences are also incorporated in this step.

With the contributing factors in mind, a design is created with predictive software to achieve the predetermined goals with consideration to budget, equipment, and operational limitations. The analytical program is run in current conditions, pumped-down circumstances, and non-ideal scenarios to ensure successful operation throughout a range of situations. This may take several iterations to refine the design to operate successfully in all of these circumstances. This may include alterations that should be recommended as the well matures and different instances arise.

The design process may be repeated at this point depending on the results from the design reviews. If the design projection doesn't fit an operator's goals or isn't recommended due to performance, it may require changing system components or operation until an ideal design is achieved. Once there is a successful, recommended analytic, the design is applied to the well production program. After the system is producing, data is continually collected to assess system and well performance in an effort to optimize.

<u>SOLUTION</u>

Applications

Operator A

This operator is a medium-sized US operator focused on production in the Williston basin. Completed in the Bakken and Three Forks formations, Operator A encountered challenges such as gas, solids, and scale. These wells were chemically treated with continuous fresh water injection. Operator A employed an artificial lift program utilizing an ESP as the first method of production. As the conversion decision approached, the engineering team explored the option of utilizing a C2560-500-320 pumping unit. Their primary goals are to avoid the cost burden associated with the "unit shuffle" and to alleviate the dip in production associated with artificial lift conversion.

Utilizing in-house engineering resources, Operator A designed and analyzed each proposed C2560 SRP system vs tower unit actuated SRP system vs ESP system projections.

Well A-1

This well has an oil API gravity of 41°, 50% water cut, and relatively mild deviation as there was only one 75 ft section of sideloading above 200 lb/25 ft. The ESP previously made an average of 330 bfpd in the month before it failed. As forecasted from the predictive software and system design, the targeted SRP production was 350 bpd at 5 spm.

Well A-1 was planned according to the process listed previously. Operator A chose to employ a C2560-500-320 in the 2nd crank hole for a 275 in surface stroke. They utilized an 86 taper steel rod string with high strength alloy sucker rods below 1-1/4 in fiberglass rods, and 625 ft of sinker bar to keep the string in tension. A 1-3/4 in insert pump was set at approximately 9900 ft with a desander. The operator chose to utilize this design with a fiberglass string and the 2nd crank hole because it depicted more production than the other systems. The fiberglass keeps the rod string light and provides improved downhole pump stroke. The light rod string and 275 in stroke length keep the gearbox loading low and operating comfortably.

This well has been running for 8 months. After start-up, the system was making approximately 500 bfpd-700 bfpd at 5-6 spm, achieving the targeted production rate. As fluid level decreased, the operator chose to slow the unit down over time and has been average 230 bfpd at 4 spm lately (Figure 3).

Well A-2

The next well has an oil API gravity of 41°, 68% water cut, and relatively mild deviation with only one section of high sideloading for more than 100 ft. The ESP previously made an average of 583 bfpd in the month before it failed. The targeted SRP production was 390 bfpd at 5 spm as it was depicted in the predictive software.

For well A-2, Operator A chose to employ a C2560-500-320 [LS12]in the 1st crank hole for a 320 in surface stroke. They utilized an 86 taper steel rod string with high strength alloy sucker rods and 500 ft of sinker bar. The rod string was connected to a 1-3/4 in insert pump set at nearly 9900 ft with a desander. This design was selected for variety of rod string implementation. As this was the first program with C2560s, Operator A wanted to employ various rod strings, bottom hole assemblies, and operational initiatives to thoroughly test the C2560 performance.

This well has been running for 8 months. In the first 60 days, the system was making approximately 515 bfpd at 4.7 spm, achieving the targeted production rate. This well has not experienced any downtime since startup (Figure 4).

Well A-3

The third well for Operator A has an oil API gravity of 40°, 67% water cut, and deviation includes one 200 ft stretch of high side loading above 200 lb/25 ft. This same area has a dogleg severity of under 2°/100 ft. The ESP previously made an average of 495 bfpd in the month before it failed. Targeted SRP production was 400 bfpd at 5 spm as a couple of the system's components were at limit. The high strength alloy sucker rods and the gearbox were loaded out to 99% under the estimated circumstances.

Operator A chose to employ a C2560-500-320 in the 1st crank hole for a 320 in surface stroke on Well A-3. They utilized an 86 taper steel rod string with high strength alloy sucker rods and 550 ft of sinker bar. This is to actuate a 1-3/4 in insert pump set at approximately 9700 ft with a desander. This design was implemented to test the ability of the sucker rods and the unit under these challenging conditions.

This well has been running for 8 months. In the first 60 days, the system was making approximately 405 bfpd at 4.4 spm, achieving the targeted production rate. This well had one shut down about a week after starting up due to an electrical issue (Figure 5).

Well A-4

The final well considered in this series for Operator A has an oil API gravity of 40°, 65% water cut, and fairly mild deviation with only one 100 ft section of high sideloading estimated to be above 250 lb /25 ft. The ESP previously made an average of 679 bfpd in the month before it failed. The targeted SRP production was 594 bfpd at the maximum speed of 6.5 spm.

Operator A chose to utilize the C2560-500-320 in the 2nd crank hole for a 275 in surface stroke. They chose a hybrid fiberglass and steel rod string with 1-1/4 in fiberglass above an 86 high strength alloy steel taper and 475 ft of sinker bar to keep that string in tension. This string is set above a 2 in insert pump set just past 9900 ft with a desander.

This well has been running for 7 months. The system began producing at about 400 bfpd at 6 spm. The well has since decreased to produce less than 300 bfpd. This well has had 2 shut downs since start up, one due to downhole pump failure (Figure 6).

Operator A Findings

This medium sized operator has been pleased with the overall results of the C2560 technology application and has determined that their KPIs were met. With the intention of decreasing the production difference observed during the artificial lift conversion, Operator A has deemed this system technology a success despite one instance not emulating the predicted model. This operator is moreso satisfied with the design flexibility present in a beam unit possessing 4 stroke length options and the ability to meet the well's needs in different production phases. Operator A uses the COPAS accounting method, so they incur asset depreciation if the assets are transferred among different wells. The asset depreciation in addition to the operating expenses required to complete a "unit shuffle" was considered a drain on the operator's budget. They found it more profitable to convert to a long stroke beam unit sooner with little to no production dip, as opposed to converting to a long stroke tower unit or continuing ESPs and later converting to a smaller beam unit with an associated production dip. The increased production over other SRP technologies and the avoidance of "unit shuffle" cost was the ultimate deciding factor.

Operator A has chosen to entirely alter their artificial lift program to include the long stroke conventional 2560-500-320 pumping unit after an ESP run because this singular unit can accommodate the well's production until the end of its life.

Operator B

This operator is a very small US operator focused on production in the Williston basin in the Bakken and Three Forks formations, Operator B encounters primarily gas, as well as solids, and minimal scale. They chemically treat their wells in batches of fresh water. Operator B typically utilizes an ESP as the first form of artificial lift after the well stops freely flowing. However, their wells are described as very hot and salty (salinity of 1.2 with treatment), and this operator has widespread premature ESP failures. Operator B was looking for a long stroke SRP solution that could be used as the first form of artificial lift, displacing an ESP. They consulted with the technical team about the application of a C2560-500-320 pumping unit in such a situation. An application engineer on the technical team created several iterations of designs capturing different stages of the well's life.

Operator B's primary goal is to maximize production without the implementation of an ESP. They want to utilize one artificial lift system throughout the entire life of the well.

Well B-1

This well has an oil API gravity of 43°, 68% water cut, and relatively mild deviation. The highest sideloading is noted around the kick-off point, predicted to be around 150 lb/25 ft. There was not a previous artificial lift system to base a SRP system target on, as the well was free flowing. So, the intention was to maximize and optimize the conventional long stroke SRP system. Predictive software indicated the potential production to be 1100 bfpd.

Well B-1 was designed according to the process listed in the design section. Operator B elected to use the recommended design with a C2560-500-320 in the 1st crank hole for a 320 in surface stroke. They had a preference for an entirely steel string, so an 86 high strength alloy steel with 1000 ft of 1 in sinker rods actuated a 2-3/4 in tubing barrel pump set at 5000 ft with a desander. This design was chosen to accommodate their equipment preferences and to achieve their ambitious production target.

This well has pumped for 5 months. At initial start-up, the system was flumping to make 1700 bfpd. Once the well stopped assisting the artificial lift, the SRP system successfully made an average 1200 bfpd at

6.5 spm, surpassing the targeted production rate. There was one shut down due to a controller error. Today, the system has been slowed down to 5.8 spm to steady operation and is maintaining a production average just under 1000 bfpd (Figure 7).

Operator B Findings

This operator has been impressed by the capability of the technology implemented and has determined their KPIs were satisfied. This application is continuously monitored, and the performance reviewed monthly with the tech team for optimization opportunities. The design was successful in completely displacing the ESP and capable of producing enough to begin drawing down this very productive well's fluid level. Operator B intends to use the C2560-500-320 as the first and last form of artificial lift on this well.

CONCLUSION

A SRP system with this pumping unit technology could completely displace an ESP. It can also avoid the production dip associated with artificial lift conversion because it can pump more fluid per minute than other long stroke geometries. Field personnel find the technology advantageous because of the familiarity, simple operation, and the ease of reduced maintenance associated. With the design of the beam pumping unit, including the flexibility of 4 stroke lengths and the ability to stroke up to 6.5 spm, this long stroke unit can be utilized through the end of a well's life. A versatile, conventional pumping unit proved the technological capability to produce unconventional results in a variety of applications. This pumping unit responds to multiple operator challenges, whether it's reduced maintenance, lowered capital and operation expenditures, or ambitious production target.

REFERENCES

Lufkin Rod Lift Catalog 2020

https://www.nord-lock.com/en-us/superbolt/products/tensioners/

TABLES AND FIGURES

Tables

Table 1

Specifications

	Model				
	LS-1824-365-300	LS-1824-427-300	LS-1824-470-300	LS-1824-500-300	LS-2560-500-320
BASIC PARAMETERS					
Rated polished rod capacity (lbs.)	36,500	42,700	47,000	50,000	50,000
Stroke length (in.)	300	300	300	300	320
Rated torque (in.-lbs)	1,824,000	1,824,000	1,824,000	1,824,000	2,560,000
GEAR REDUCER					
Reducer gear ratio	28.89	28.89	28.89	28.89	28.29
Oil storage capacity, gal/US	168	168	168	168	247
247 Lubricant	AGMA ISO VG 220 EP#5 for operation down to -0.4°F (-18°C) AGMA ISO VG 150 EP#4 for operation below -0.4°F (-18°C) down to -22°F (-30°C)				
BALANCE ASSEMBLY					
Weight of cranks (lbs.)	9,370	9,370	9,766	9,766	9,947
Structural unbalance (lbs.)	-4,563	-4,779	-4,168	-4,168	-5,098
Cranks (part number)	CCR04-01	CCR04-01	CCR05-01	CCR05-01	CCR06-01
Effective counterbalance (ECB) cranks only (lbs.)	-308	-525	342	342	-849
Maximum ECB (lbs.)	30,128	29,911	30,822	30,822	30,877

Figures

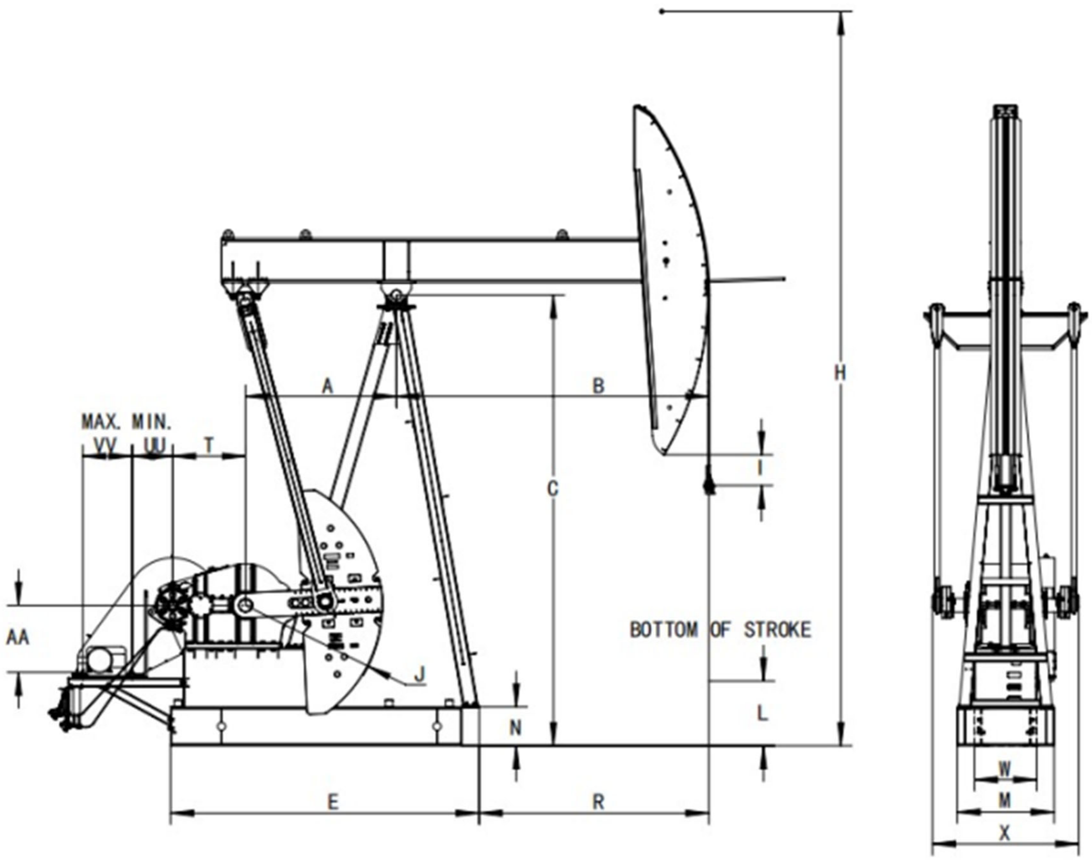

Figure 1

Figure 2

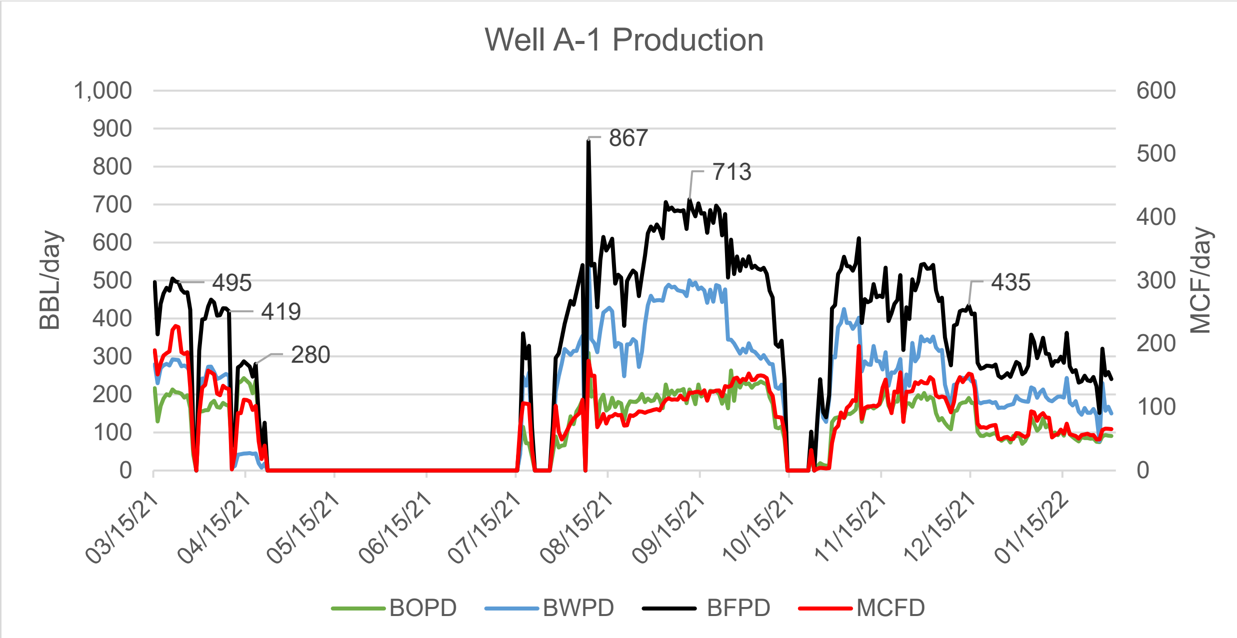

Figure 3

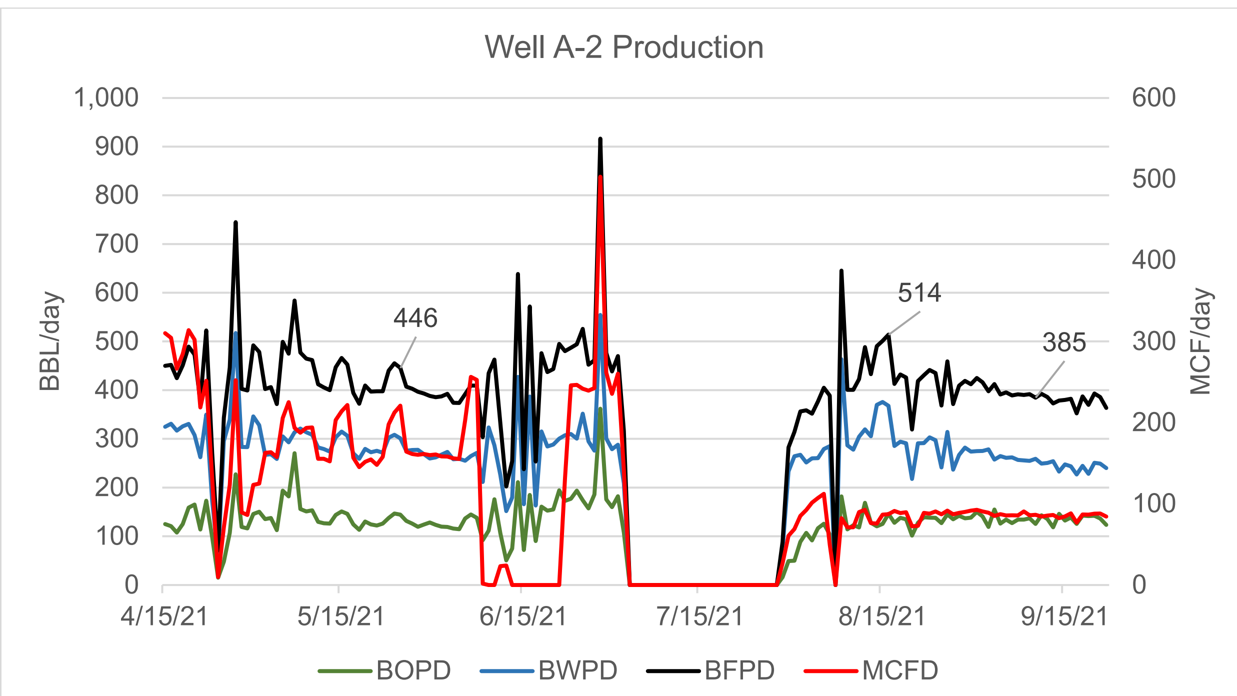

Figure 4

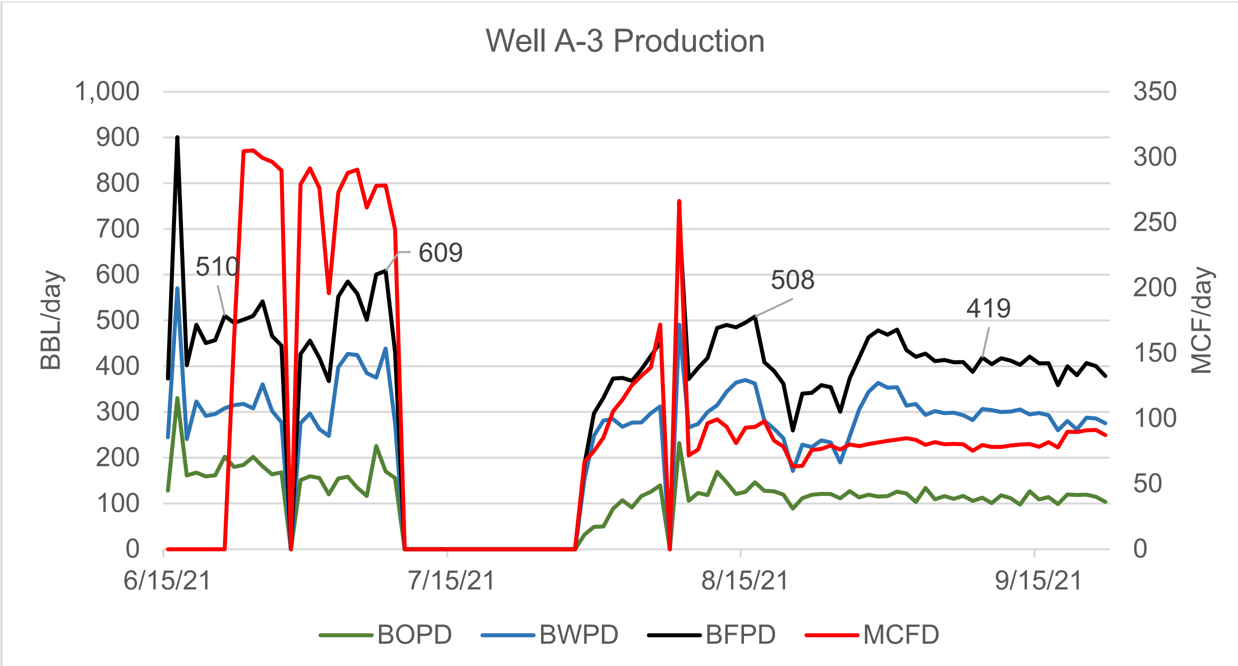

Figure 5

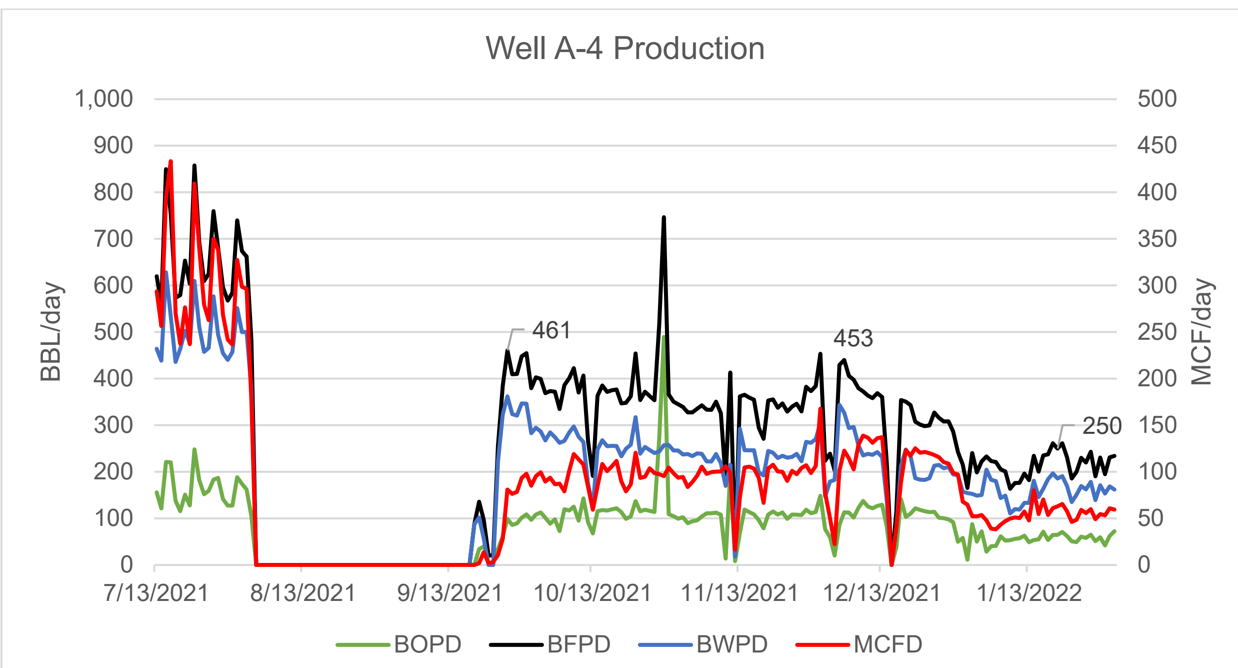

Figure 6

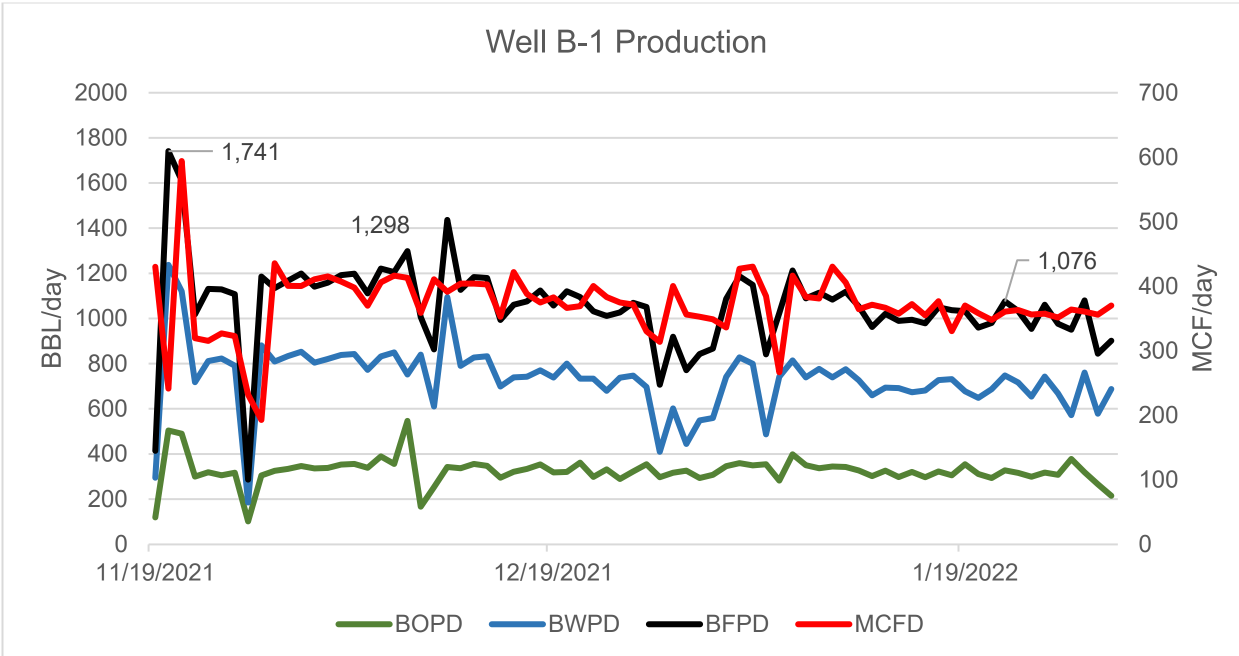
Well B-1 Production
BBL/day
MCF/day
2000
1800
1600
1400
1200
1000
800
600
400
200
0
700
600
500
400
300
200
100
0
1,741
1,298
1,076
11/19/2021
12/19/2021
1/19/2022
BOPD
BWPD
BFPD
MCFD

Figure 7