PERFORMANCE EVALUATION OF LIFTPRIME PUMP IN DELAWARE BASIN (CASE STUDY)

Nurbol Bekbossinov, Mohammad Masadeh, Nelson Ruiz,
Diego Hernandez & Mohamed Hamoud

Baker Hughes Company

ABSTRACT

Main objective of this paper is to introduce oil and gas industry installation case of newer LiftPrime pump model in the Permian Basin. It is intended to show a reader pump performance and comparison to older models based on operator's target production rates and electrical and mechanical parameters that of focus when designing and selecting an ESP system.

New pump model operates in a wide range of flowrate and houses a greater number of stages which proves to help better lift a given amount of fluid compared to older models. Opportunity presented itself to study two wells with similar pump settings depths and production rates and it has been decided to evaluate the performance of new pumps.

Overall, it is observed that new LiftPrime extended range pumps seem to be helping to cover most of the production time on most unconventional wells due to their decline nature. Another observed benefit is that operating range is wider than on older designs and on multiple occasions older models end up close to the extreme or out of range operation based on the test flow data. This impacts the performance and the total unit run life of ESP system, reduces the number of shutdowns, and in turn lowers operational costs for an operator. Wells with new and old pump designs will be presented to a reader with real-time operational trends. Additionally, several production match cases were done using in-house software to help narrow down different underperforming conditions of given units. It is believed that this paper may serve a reader with practical application of different ESP models in real conditions and the effect of operational changes on their performance.

NOTES ON UNCONVENTIONAL PLAYS

It is well established that unconventional reservoirs hold high potential and store large amounts of hydrocarbons. However, due to low permeability the production trends significantly differ from conventional reservoirs. Conventional reservoirs can be controlled by constant rate and maintained for certain a certain time of production. This is not the case with unconventional reservoirs. Rates decline in several weeks to months (Figure 1). Such behavior requires proper reserves estimation as well as properly analyzed production outlook on newly drilled and completed wells. To better access the hydrocarbon stored volume wells are drilled horizontally and completed by creating more surface area through hydraulic fracturing with tighter well spacing.

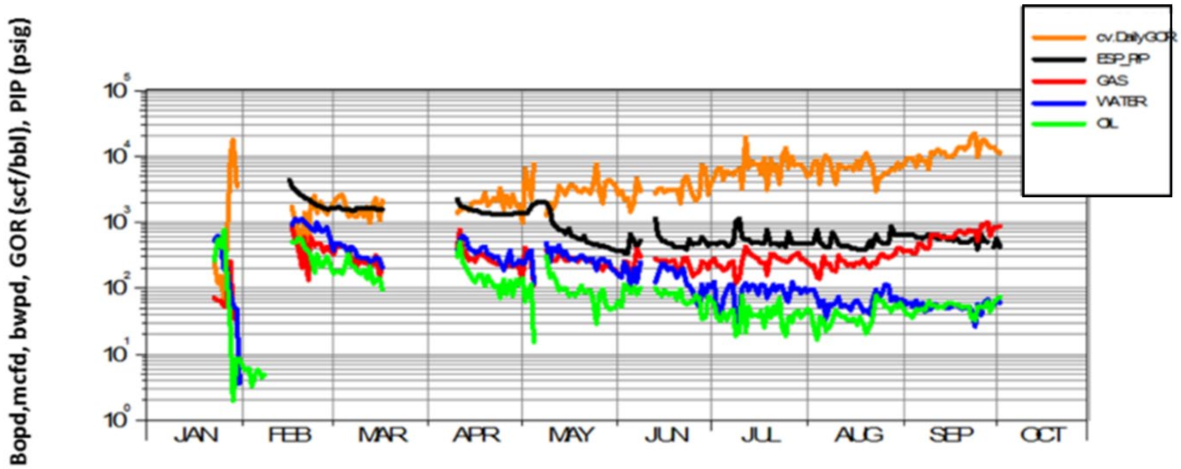

Figure 1: Sample production rates behavior on an unconventional well (Oyewole 2016).

Once wells are flown back and first drops of hydrocarbons are seen on the surface, artificial lift of choice is installed down a hole with purpose of helping to lift the hydrocarbons to the surface. Nowadays, primary choices are either gas lift or electric submersible pumps (ESPs). Proper designs in accordance with target production rates and wellbore geometry are completed. Normally, gas lift requires less operational attention as opposed to ESPs, however, properly sized, and optimized ESP can pull on reservoir fluid more aggressively delivering larger volumes to the surface. Additionally, design of choice highly depends on an operator's cashflow model and budget.

<u>CASE STUDY OVERVIEW</u>

In this paper ESP technology is discussed in detail comparing LiftPrime series pump with older portfolio pumps. Operator's request was to design similar ESPs on all wells as much as possible. Therefore, one well (Well A) is designed with a combination of gas handler pump (GP) and older portfolio pump (OP) (390 stages) while Well B is sized with combination of gas handler pump (GP) and Liftprime pumps (LP) (425 stages). However, the total unit length resulted to be the same and LP pumps in the same housing pack more stages.

Operator's goal was to maintain the steady production and enhance the run-life of an equipment as much as possible. Some operational challenges were related to sand guards, scale and sand, and surface facility limitations. Original designs were requested to be sized to lift ~3000 BFPD total liquid, 74% water cut, and ~300 SCF/STB-700 SCF/STB of GLR on all wells. Due to surface facility limitations, there were occasional shutdowns on all the wells. During this time, it seemed to be the case that scale settled down inside the well, which was evident during the production match cases and discussed later in the paper.

<u>WELL A PERFORMANCE</u>

This well was installed on June 12, 2022, and initial design consisted of four OP1 extended range pumps along with GP with the same number of stages. OP1 extended range pump operates nearly within ~300 to ~5000 BFPD. Unit was running until November of the same year. After the pull it was noted that intake was plugged with some scale material, potentially with some paraffin or iron sulfide. It was recommended to the operator to cleanup the well and reconsider the chemical program as they were pumping scale inhibitor down through the chemical treatment (CT) line. All the pumps were checked on location and later passed the shop tests. Nonetheless, unit during its short run-life was operating with no significant issues based on the performance curves and failure cause was more than likely due to the combination of scale and increased gas production (Figure 2). Unit was re-installed then with OP2 and GP pump in about three days.

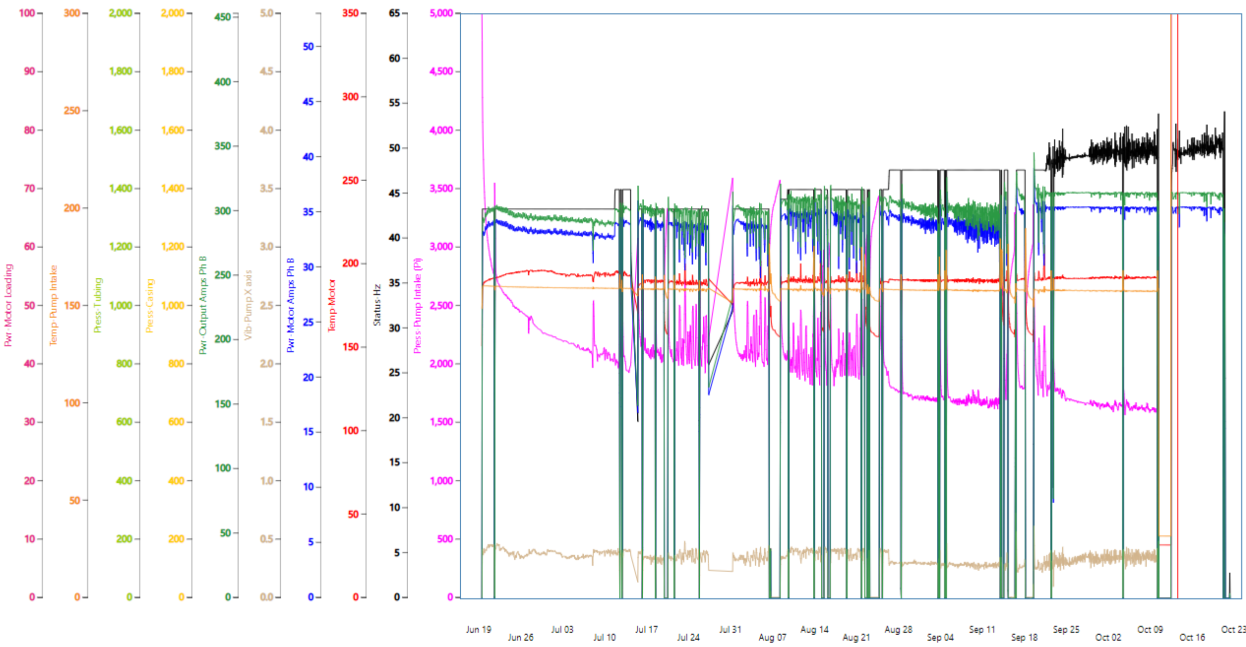

Figure 2: Performance readings on Well A original design (GP + OP1).

First ESP unit was operating mainly at setpoint frequency mode for the most of its run-life. Based on amperage curves unit performance was hindered by gas production. Later in time operator wanted to try and reduce the amperage band and it was passed to PID current control mode on VSD. After the second to last shutdown event sensor data was lost and unit was eventually grounded in couple of days. Overall, performance of this pump combination was satisfactory, and unit gradually decreased the bottomhole flowing pressure from ~3500 psi down to ~1550 psi.
Second time this well was producing with GP and OP2 pump combinations. Compared to OP1 pump it has a shorter operating range of ~2000 to ~4000 BFPD. Well B was still moving the total liquid within the operating range of the pump and due to the nature of operation at relatively slower frequency it was projected that this pump would last for longer period.

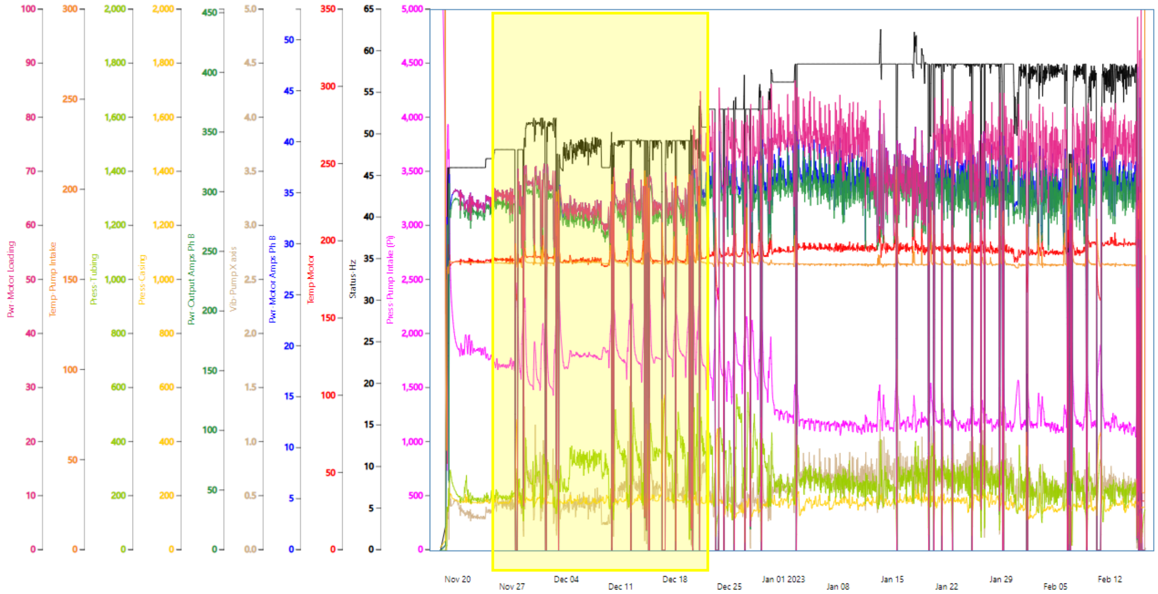

Figure 3: Performance readings on Well A second run (GP+ OP2).

Second design was initially operating at a setpoint frequency, however, after the shutdown on external intervention, unit had difficulties running at a fixed frequency and therefore was passed to PID current control mode. Sequence of operational changes are highlighted in the yellow box (Figure 3) and shown on Figure 4.

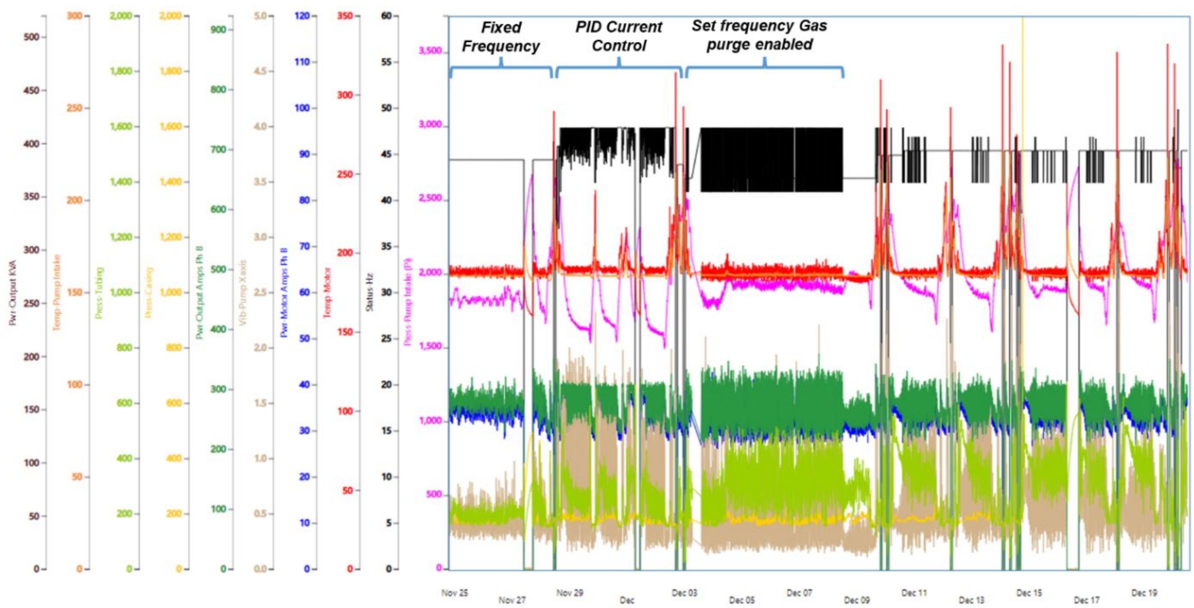

Figure 4: Troubleshooting sequences on Well A (GP + OP2).

Unit was comfortably operating at 44Hz. After the next shutdown PIP pressure dropped followed by the drop on motor amps. During the low amp load time duration PIP and motor temperatures started rising. Unit eventually shutdown on motor temperature alarm. It was discussed with the customer and decided to pass the unit to PID current control mode in hopes of maintaining the drawdown, temperature, and electrical readings. It seemed to be the case that cycle was repeating and unit was adjusting the frequency to maintain the target amperage on the motor, ~35 Amps. However, operator was concerned about the cyclic behavior and team decided to tackle the issue by passing the VSD to set frequency mode and enabling the gas purge mode. Target frequency in this mode was ~43Hz, low speed clamp (LSC) was set to 42Hz, and high-speed clamp (HSC) was set to 47Hz. Figure 4 shows that frequency was adjusting to either LSC or HSC depending on the motor amperage. For about nine days unit accepted the change and maintained the PIP as well as motor temperature. Operator decided to try and run the unit at set frequency disabling the gas purge mode. This setting did not last for long and unit again started shutting down on high motor temperature and exhibiting cycling readings as before. It has been quite challenging to pass the unit back to gas purge mode as ESP was not accepting the mode again. Several production match cases have been conducted in Autograph PC based on real production and electrical data. From the match cases it was not too difficult to match the operating frequency of tandem pumps, however, it was evident that upon matching the frequency motor amperage was less than actual readings. This indicates that total composite fluid density that the pump is moving is heavier than just oil, water, and gas mixture. Therefore, it is indicative of some scale movement and agrees with the history on this well from first install.

WELL B PERFORMANCE

Unit on this well was installed on July 14, 2022. It was running only in setpoint frequency mode and was never engaged in gas purge or current control modes. Judging by the high degree of fluctuations on motor amperage, unit is experiencing larger volumes of gas interference since the middle of the January. The LP housing has a range from ~700 to ~4000 BFPD. PIP drawdown was overall smooth throughout the run-life of the unit and decreased from ~3600 psi down to ~900 psi (Figure 5). Overall performance on this well is satisfactory by the operator and no significant operational adjustments were required aside from only case matches with the production data.

Figure 6 shows enhanced view of the highlighted yellow region from Figure 5. Motor amperage fluctuates anywhere between 30 to 44 Amps. Motor temperature is steady with gradual pump intake pressure drawdown. Vibration increased a little higher and fluctuates between 0.3 to 1.2 G, which is acceptable and may be indicative of potentially two things; one is that there is also scale buildup inside the pump and second one of the pumps may be out of the operating range. These issues are observed during the match cases.

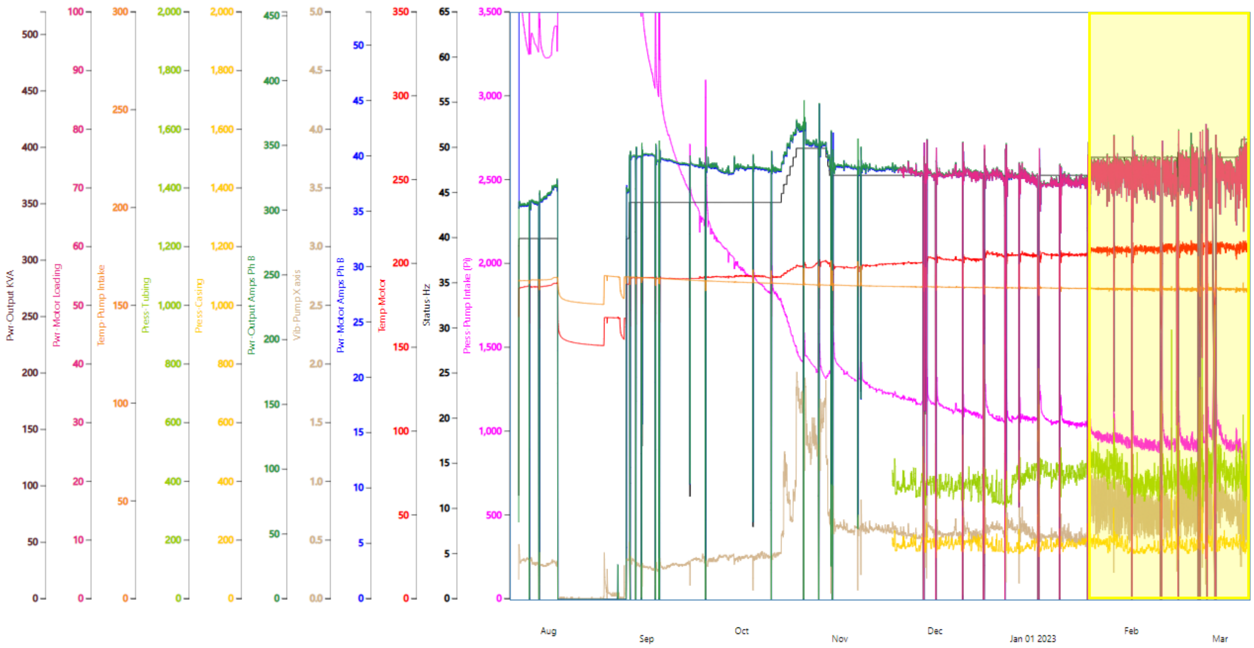

Figure 5: Performance readings on Well B (GP + LP).

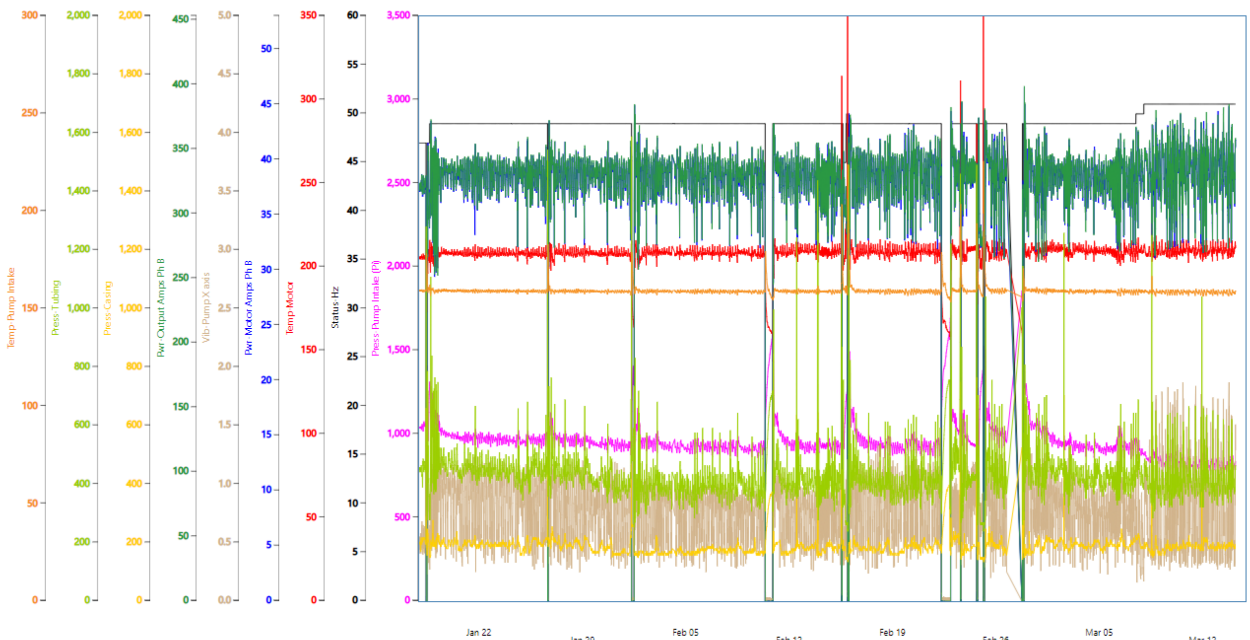

Figure 6: Performance readings on Well B since the middle of January (GP + LP).

RESULTS AND DISCUSSION

As mentioned throughout the paper, all wells on this well pad have scaling tendencies. Another well on the same pad, which was not mentioned before in this paper, failed, and had a broken shaft. Once equipment was pulled and checked it was evident that severe scaling caused motor stall and eventually resulted in a broken shaft. In discussion with the customer, it was agreed that production match cases will be conducted using our in-house software. The primary purpose was to understand where the operating points are, what could be the reason for unit underperformances and what actions can be taken to tackle the issues. During the first ESP run on Well A it was not of focus in doing match cases and minimal production data was given to accomplish the task. Nonetheless, over five months first install on Well A total downtime was 950 hours (27%). Roughly 67% of the total downtime hours was related to downhole issues such as motor stall and motor temperature alarms.

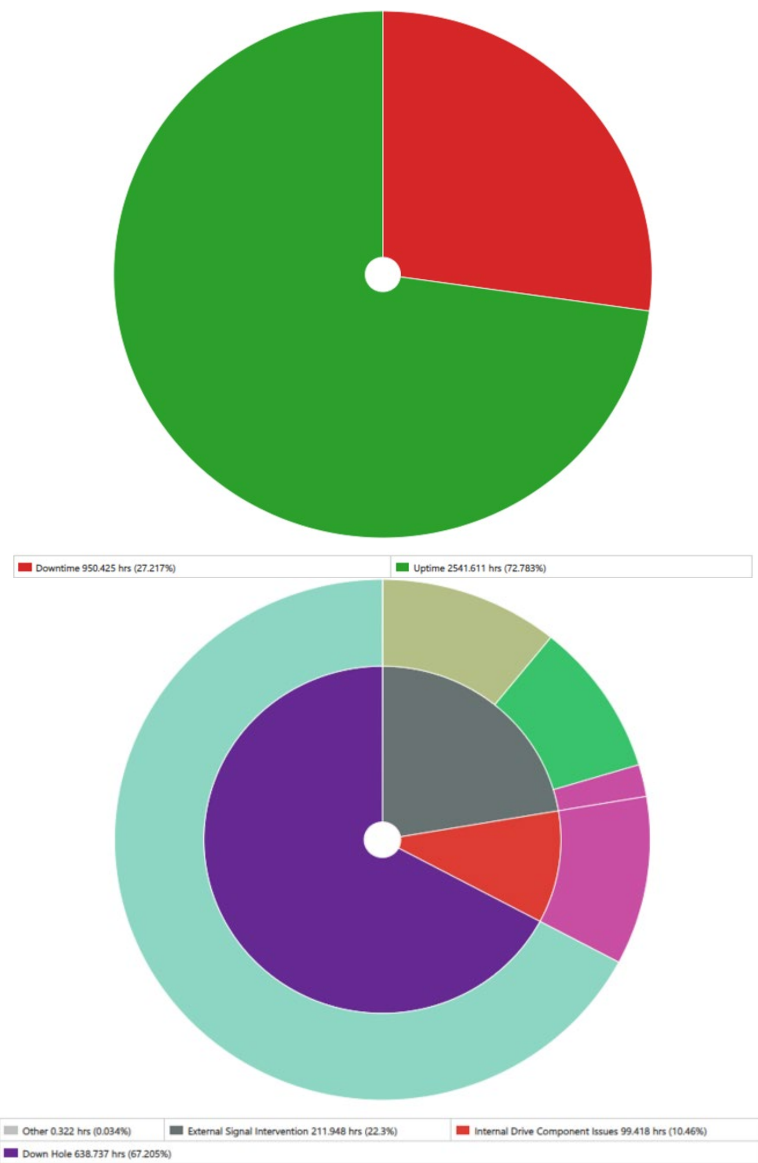

Figure 7: Well A (first run GP + OP1) total uptime/downtime pie chart.

Even though, Well B was put online about a month later than Well A, within first five months of its run-life it had roughly 584 hours of downtime (17%). From total downtime hours, zero hours were related to downhole problems and were mainly related to VSD service maintenance and external interventions.

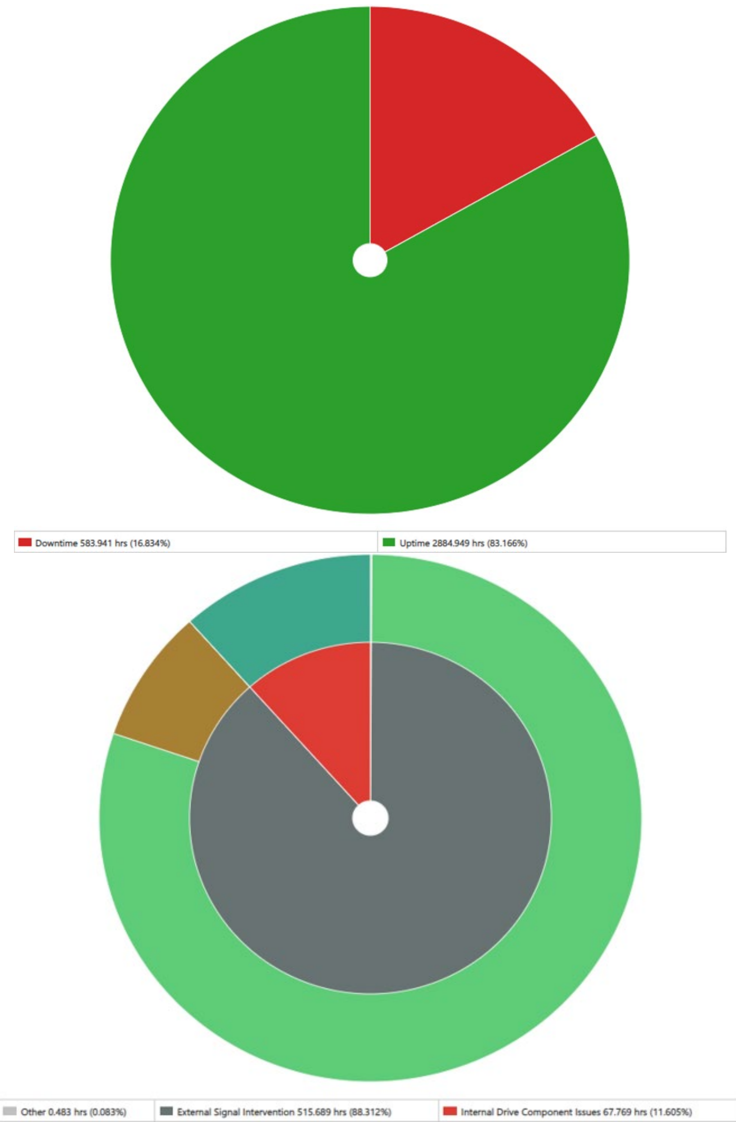

Figure 8: Well B total uptime/downtime within first five months.

A more in-depth analysis has been done in comparing the second run on Well B with Well A since operator wanted to match running parameters within our software. Both wells have relatively the same pump intake depth. Well A is at about 10,170 feet MD and Well B is at 10,027 feet MD. Based on the production data unit in Well B on average was dealing with ~48% more gas and move ~29% more total liquid volume. Based on the match cases it was estimated that unit in Well B on average had 10-15% more gas in the pump after the high-volume gas separator. However, based on the match cases throughout the run-life Well B had 4-8% higher efficiency than on Well A.

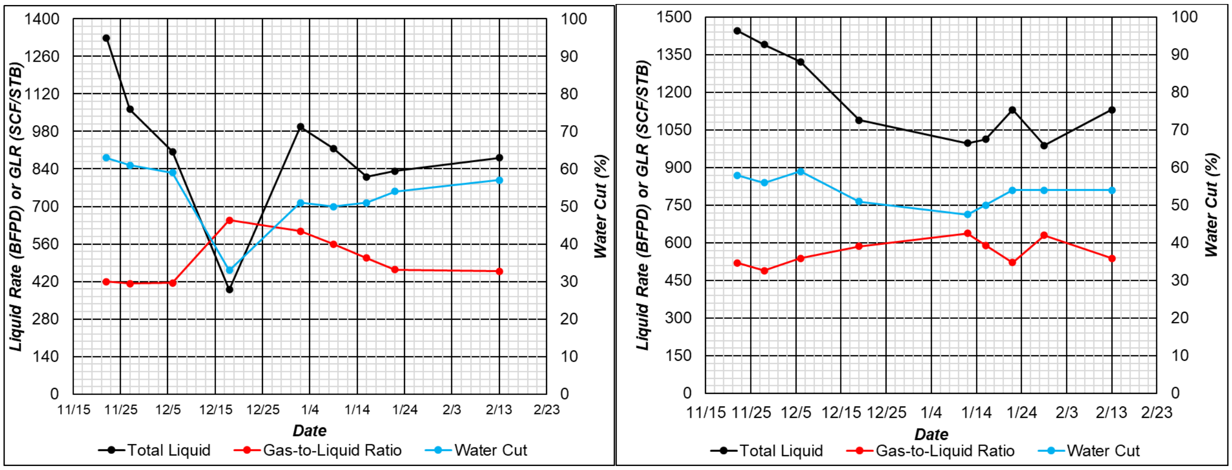

Figure 9: Production trends for match cases on Well A (left) and Well B (right).

A reader may ask a question as to why Well A having less gas production and having to deal with less gas in the pump had lower pump efficiency as opposed to Well B. First, Well B was moving overall slightly higher production rates. Larger volumes of liquid better assist the pump unit in carrying the gas to the surface. Second, partial blockage at the intake or space reduction due to the scale buildup on the diffusers or impellers may reduce the movement of total liquid; gas being lighter and more mobile passes through hindered pathways much easier. This may explain the cyclic behavior of pump performance readings (Figure 4). Lastly, as it is well known pump operating range has a high impact on pump efficiency.

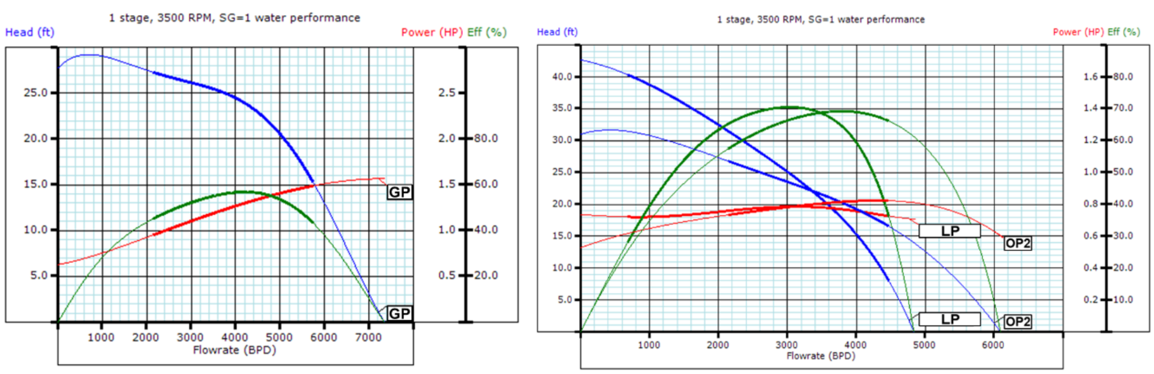

Figure 10: Pump operating ranges for GP (left), LP and OP2 (right).

On both units when matching the production data in Autograph PC, the operating frequency at a certain day of production, software was showing less speed required to move the same amount of fluid. This is, again, indicative of flow hinderance due to the presence of gas in the pump. Another important parameter for our match cases is operating motor amperage. In order to get close to true readings from the sensor it was evident that both units required higher break horsepower input from the motor. Both wells were producing less than 2000 BFPD total liquid. All pumps are more likely operating in predominantly downthrust position. From Figure 10 operating points on Well B are out of the range and therefore favors the additional reason for higher break horsepower input from the motor. For Well A, gas handling pump is out of the range and upper tandem pumps were still within the operating region. From the match cases surface power consumption was estimated in the software (Figures 11 and 12).

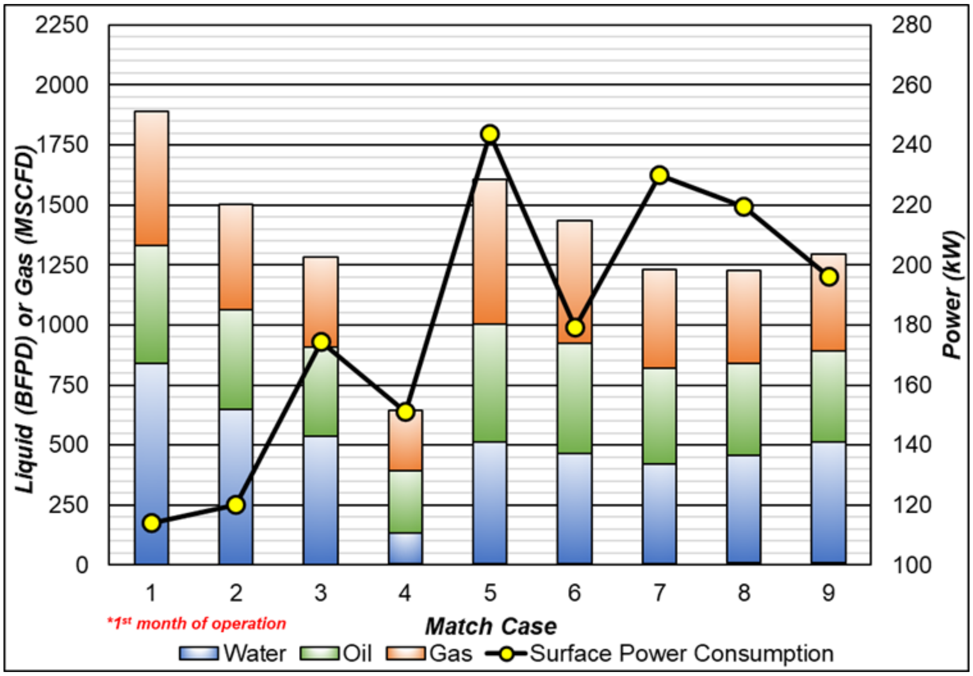

Figure 11: Production rates and estimated power consumption on the surface (Well A).

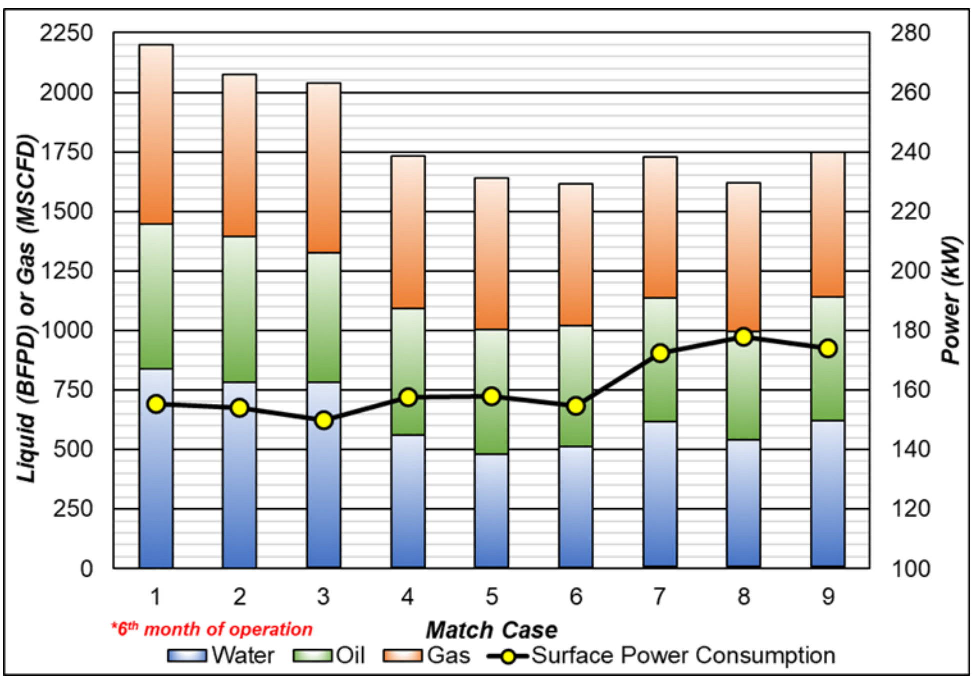

Figure 12: Production rates and estimated power consumption on the surface (Well B).

On first two match cases the estimated power consumption on Well A is ~20 to 30 kW less than on Well B. As production declines further power consumption on Well A is fluctuating but increasing, same happens on Well B, but increase is gradual over time. Well A unit failed and found to be grounded downhole middle of the February 2023. Unit on Well B is still running. However, in comparing the uptime and downtime between the two units operating times were scaled from the moment when second install on Well A came online until it failed.

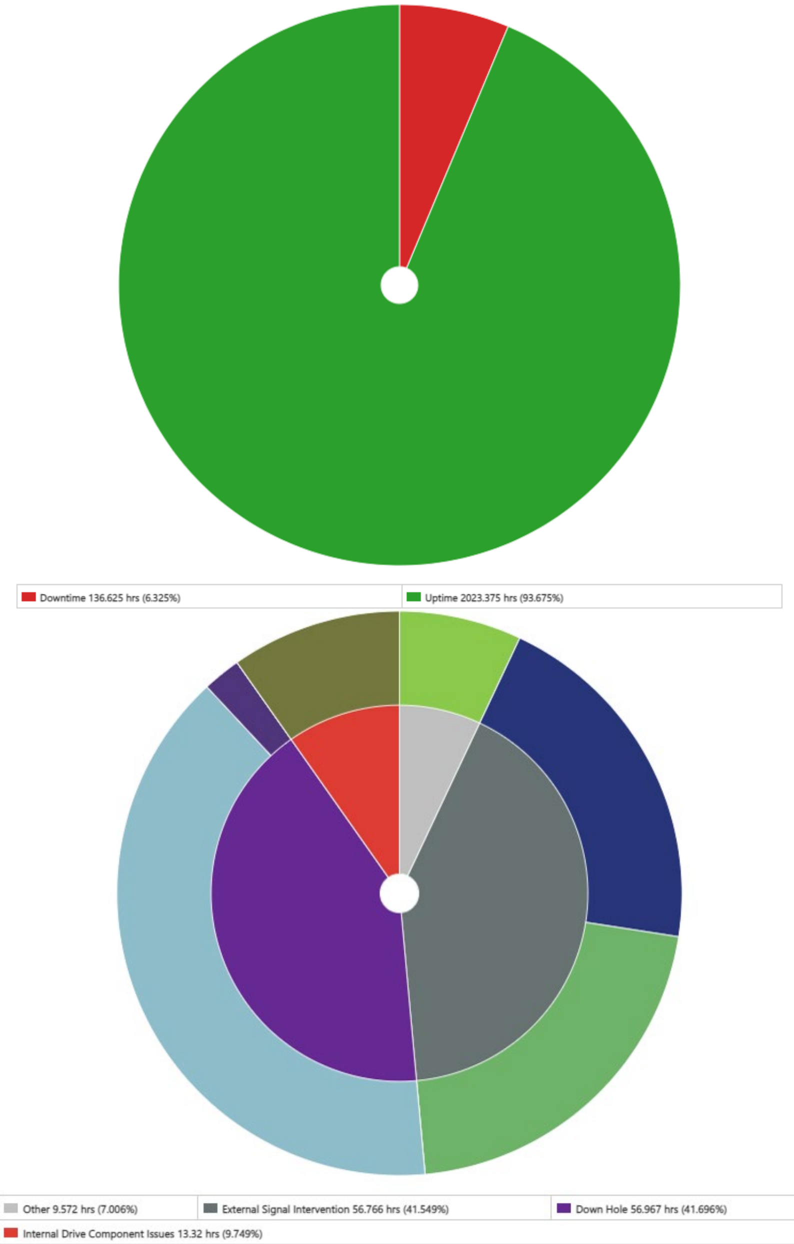

Figure 13: Well A (second run GP + OP2) total uptime/downtime pie chart.

Second run on Well A resulted to have less downtime compared to the first run, but overall total run-life was only half of the first run. Total downtime on second run resulted to be ~6.3% out of 2160 hours being in the hole. Approximately 42% of total downtime was due to the downhole issues as well as the high motor temperature alarms, the rest was related to external intervention.

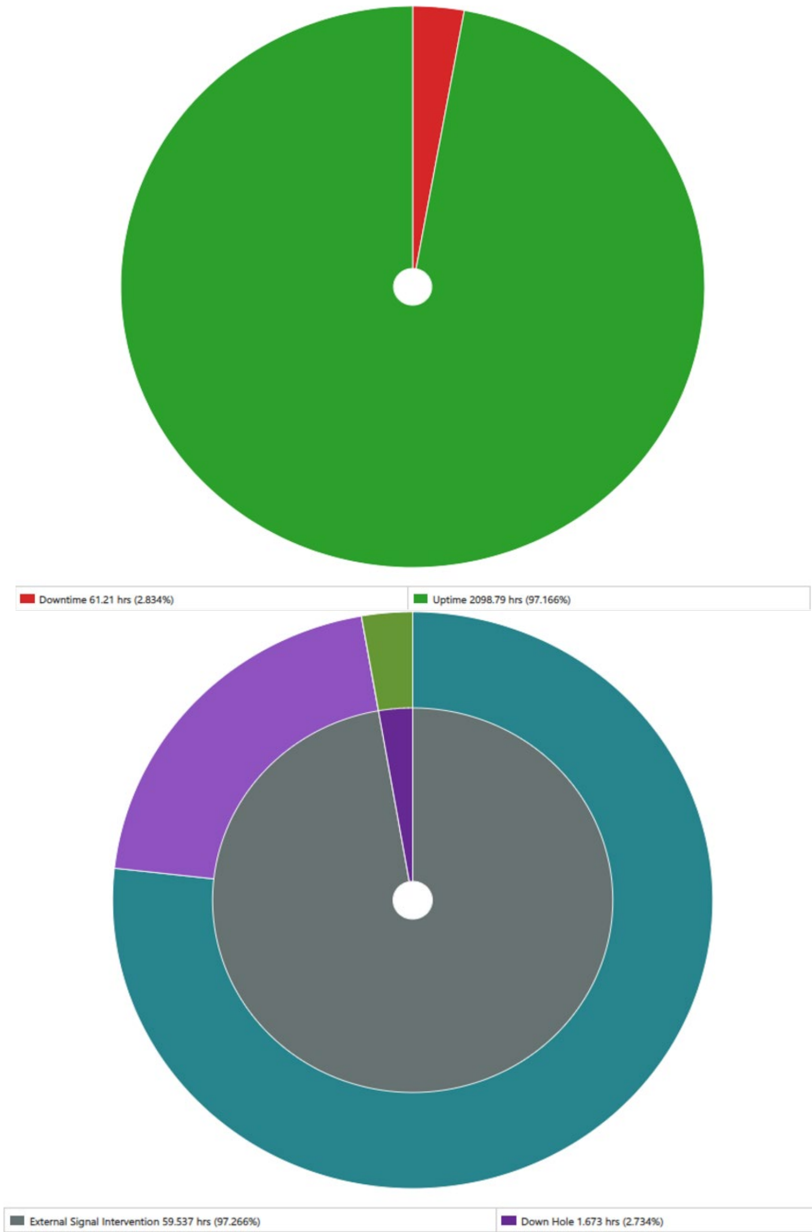

Figure 14: Well B total uptime/downtime pie chart (time scaled for Well B run-time).

Out of 2160 hours of operation, unit on Well B had about 2.8% downtime. Roughly, 2.7% out of total downtime was related to down hole issues. Unit on Well B had less downtime due to the downhole conditions. Considering the observations from the past teardowns on units from other wells and from match cases in the software all units moving scaly material. While pump is online and operating due to the centrifugal forces heaver parts of the fluid will move with the liquid at an outer edge within spaces between impellers and diffusers while gas being lighter will mostly concentrate towards the middle. Issue is that when units are shutdown, fluids and scaly materials settle down and composite liquid inside the pumps will tend to reach the potential equilibrium. Therefore, scaly material will inevitably be spreading out throughout the whole space between impellers and diffusers. It gets into shaft spaces between the impellers, hardens and builds up on the walls of diffusers and/or impellers. Further, upon the start of a unit it will be a lot more challenging to reach the same operational conditions as before and unit may need some time to establish a proper flow. Nowadays, most ESP are built with shafts, impellers, diffusers, and other components to withstand heavy-duty conditions. Overall, no units on Well A and B had a broken shaft. Both wells had no issues starting up and getting back to the normal drawdown conditions indicating that units on both wells were robust in handling scaly conditions.

CONCLUSIONS AND KEY TAKEAWAYS

In this paper the main point of focus has been the comparison between performance of older with newer pump models. Well A first run with GP and OP1 pumps had failed but not due to the pump underperformance. Primary reason was severe scale and solids buildup at the intake levels, which significantly hindered pump operation. OP1 pump being an extended range pump overall showed great performance and was satisfactory by the operator. Second run on Well A with GP + OP2 pumps had failed primarily due to the combination of scaling and operational range. In a matter of a month total liquid production moved down from ~2500 BFPD to ~800-900 BFPD. Therefore, it was not much in favor of operating at these production points. Primary reason installing these pumps was to be able to handle larger total composite density of the fluid. OP1 pump had a history of operating at these conditions as opposed to LP. It could also be the case that Well A overall had to deal with a lot more scale and solids movement than unit on Well B, which could have reduced the run-life by a higher factor. But it could also be the case that unit on Well B having more stages in the same housing deals with these conditions better than units on Well A. A more comprehensive experimental and theoretical study needs to be done in this regard. Well B with GP and LP pump is running, however, similarly to other unit's motor amperage and intake pressure readings are starting to fluctuate but no shutdowns have occurred yet due to underload or motor temperature. Based on the overall experience on this pad, it is shown that LP pumps are highly operational and comparable to OP1 and OP2 pumps. Especially, considering the amount of scale these units had to deal with. Pumps operating out of the range estimated to cause higher power consumption on the surface compared to extended range pumps, which can affect the operator's operational expenditures. Overall, final point to make is that extended range pumps are projected to help an operator to cover most of the production life on a given unconventional well. However, proper analysis of production forecast as well as proper well cleanup operations need to be done to properly size an ESP and maximize the total efficiency of a unit.

BIBLIOGRAPHY

- Baker Hughes Company, "Submersible Pump Handbook", 2021.
- Oyewole, P., "Artificial Lift Selection Strategy to Maximize Unconventional Oil and Gas Assets Value", 2016, SPE-181233-MS.
- Pradhan, Y., Xiong, H., Forrest, J., Zhu, J., Kianinejad, A., Cui, A., and Gao, S., "Determining the Optimal Artificial Lift Implementation Strategy in Midland Basin", 2017, URTeC-2668625.