GAS LIFT AS A LATE LIFE ARTIFICIAL LIFT STRATEGY: DEEP GAS LIFT IN THE LATERAL OF HORIZONTAL WELLS

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ABSTRACT

Horizontal wells are the largest capital investments made in the Permian and return on investment is essential. The project was developed to analyze the sustainability of gas lift as final form of artificial lift for unconventional horizontal wells. A pilot to run gas lift equipment deep into the lateral was developed, which involved meticulous candidate and downhole equipment selection. Two horizontal wells were selected from the Midland Basin, and deep gas lift was installed far into the lateral.

BACKGROUND

Horizontal rod pump wells require a large capital investment, and the reliability has historically been lower than that of a gas lift well. When analyzing the data, it was confirmed that the trend of horizontal rod pump failure rates is significantly higher. However, the failure rate of horizontal rod pumps has decreased over time due to better equipment selection and design (**Figure 1**). The 2020 failure rate data shows a continued decline in failure rate; however, it needs to be considered that the wells were being curtailed during a low commodity price environment. In addition to a higher failure rate, the lease operating expense (LOE) of horizontal rod pump wells are significantly higher than the LOE of the horizontal gas lift wells (**Figure 2**). With the determination that both the LOE and failure rate were significantly less for gas lift wells, the team wanted to focus on utilizing gas lift as an end-of-life artificial lift form. Prior to this project, plunger installation and intermittent gas lift were some of the solutions used to prolong the gas lift artificial lift phase. With looking at this form of artificial lift in a new lens, the team came up with a new solution to trial: install gas lift valves into the lateral to see if the opportunity of getting to inject gas deeper would not only increase sweep efficiency, but also would become a last form of artificial lift before abandonment.

WELL SELECTION & NODAL ANALYSIS

Candidate selection was prioritized on several factors: gas availability at the battery, future planned offset activity, and recent wellbore investments. After analyzing all the relevant factors, two candidates were selected in the asset area for execution of the pilot.

Some of the considerations highlighted throughout the theoretical modeling of this project were:

- Sensitivities run in SNAP incorporated numerous variables including: tubing size, tubing depth, injection rate, injection depth, GOR, water cut, annular vs. conventional configuration
- No “off the shelf” artificial lift simulation software can simulate past end of curve (EOC). This is attributed to software design leveraging TVD instead of MD for calculations. Nodal simulation sensitivities within SNAP showed toe down horizontal wells receive a greater impact on lower bottom hole pressure due to deeper TVD.
- Numerous sensitivities were run, and it was determined that decreased tubular size had a negligible impact on uplift potential

- When executing lowering the deepest point of injection further into the lateral, it is imperative that the lateral has been cleaned out. With a clean horizontal wellbore, premature plugging and abandonment will be prevented.

Both candidates selected had lateral lengths of one mile. This decision was attributed to having comparable pilot wells, as well as first trialing on shorter lateral lengths. Candidate 1 selected was a Wolfcamp B well with a lower GOR, while candidate 2 is a Wolfcamp B well with a higher GOR. **Figure 3** shows nodal analysis for the previously installed gas lift design in comparison to deep gas lift design for candidate 1.

EQUIPMENT & DESIGN

When installing gas lift valves, many things need to be considered from proper configuration to valve selection. One main concern in this project was the injected gas not reaching the end of the lateral, and the gas instead being stolen by the perforations. Another concern was the gas lift valves (GLVs) set further into the lateral getting plugged due to scale or fill. With those concerns in mind, the pilot design selected was conventional gas lift configuration above the packer, and annular gas configuration lift below the packer. Thus, a crossover packer was selected.

With this configuration, a conventional gas lift surface set up was used. Gas is injected down the annulus and uses tubing flow gas lift valves to unload the backside of the packer. Once the fluid level reaches the top sub of the DeepLift cross over packer during the unloading process, injection gas is diverted from the annulus through an internal “snorkel”, and into the tubing below the packer. Once gas enters the below-packer portion of the DeepLift system, internally mounted GLVs send the gas to the deepest point of injection possible, ideally far into the lateral section of the wellbore. The tailpipe acts a velocity string to help improve flow requirements across the lateral and up through the heel. Once produced fluid and gas reach the bottom of the packer, they then cross back over into the tubing through the bottom sub of the DeepLift packer and are sent to surface inside the tubing. **Figures 4 & 5** show samples of the equipment used. **Figure 6** shows examples of the theoretical flow paths through the equipment.

EXECUTION

For optimal pilot success, both candidate 1 & 2 required clean outs in the lateral before any equipment was run into the end of casing. The clean outs facilitate better wellbore integrity, execution of artificial lift design, as well as prevent premature abandonment. Scale build up and sand was cleaned out of the lateral of both candidates (**Figures 7 & 8**).

The required well work for candidate 1 began in June of 2021. The clean out for candidate 1 had a duration of 3 days, and artificial lift was installed on the following day. Candidate 2’s well work began in October 2021. The clean out had a duration of 2 days and the artificial lift was installed on the following day.

Another consideration for successful wellbore integrity was proper chemical treatment of the downhole equipment. The atomized chemical rate was increased in the injection gas, which would aid in the scale/corrosion product to treat all equipment far into the lateral. Previously, the lateral was not treated for scale or corrosion due to the deepest point of injection being higher.

RESULTS

The results of the two candidates varied in success. Candidate 1 doubled in production immediately after installation, however the installation report indicated the orifice valves were not properly installed at the end of the tubing (5,280’ into the lateral). The mistake was quickly identified and resolved with additional rig work. An unforeseen advantage to this mistake was the ability to distinguish between the production gain from the clean out versus the increase from the deep gas lift equipment installation. **Figure 9** shows the production results. The return on investment was 100% and the job paid out in 5 months.

Candidate 2 also had positive results, and the production curve decline rate was not as aggressive as originally forecasted. The return on the investment was 100% and the investment was paid out in 7 months. Candidate 2's production plot can be seen in **Figure 10.**

In comparison, candidate 2 did not benefit as much from the deep gas lift configuration initially. This was attributed to candidate 1 having a much lower GOR, thus candidate 1 more significantly benefitted from the increase in total GOR of the system.

The project indicates that deep gas lift has the potential to be a sustainable end of life form of artificial lift for horizontal wells. An added advantage to this strategy is horizontal wells not declining as quickly.

Operationally, it was found that the wellbores were being properly treated with the modified chemical treatment. Residuals taken from the well indicate that scale/corrosion combo product have effectively reaching the end of the lateral and traveled back to the surface.

GOING FORWARD

Five deep gas lift candidates have been identified in this specific asset area, and 3 wells are forecasted to have deep gas lift installed in 2022. The chemical program will need to continue to be evaluated to ensure the lateral is being properly chemically treated. This is imperative to prevent any future fishing jobs or premature abandonment of the horizontal wellbore.

<u>Appendix</u>

Figure 1

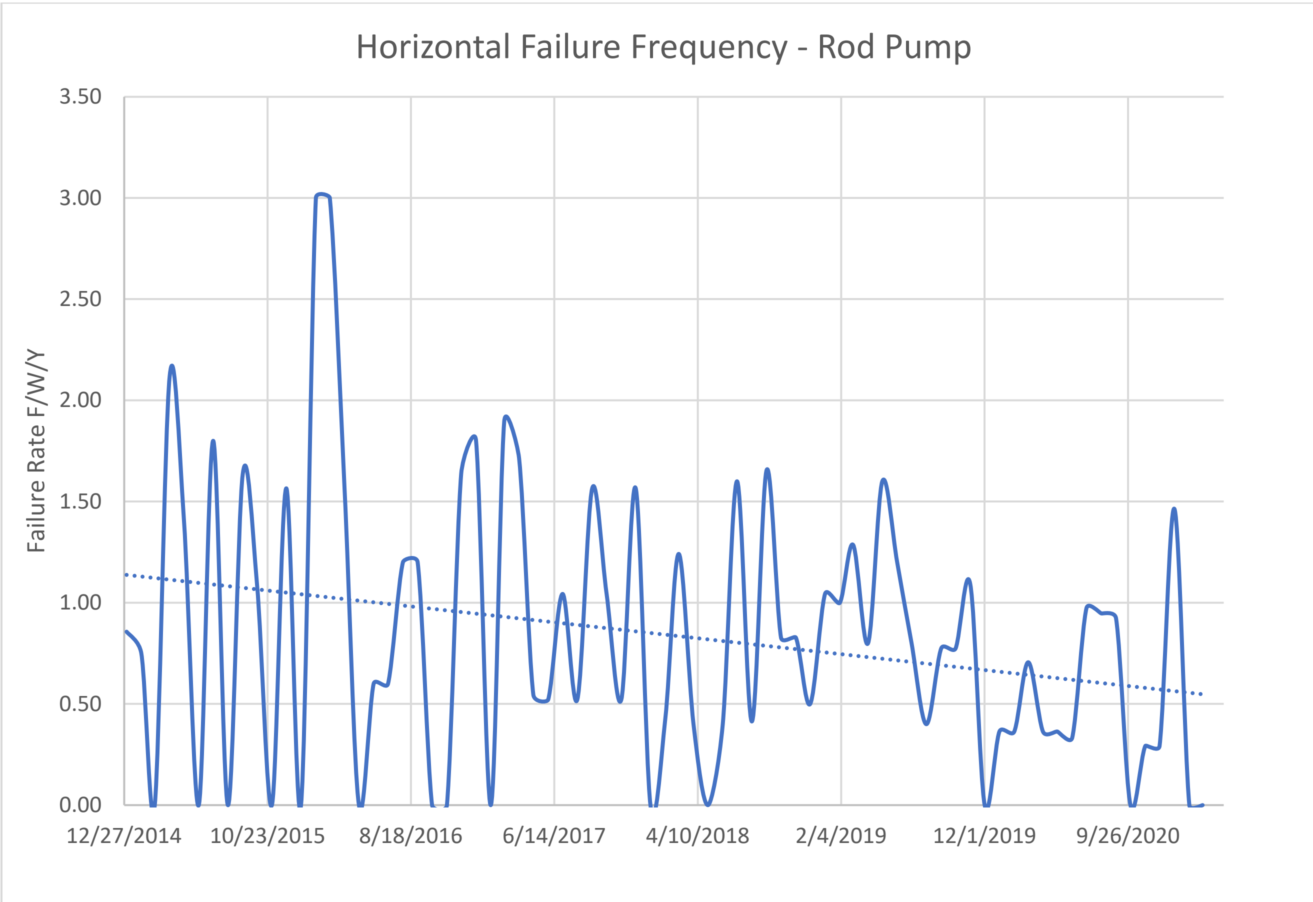

Figure 1: Above chart illustrates trend of decreasing failure rate of horizontal rod pumps over time

Figure 2

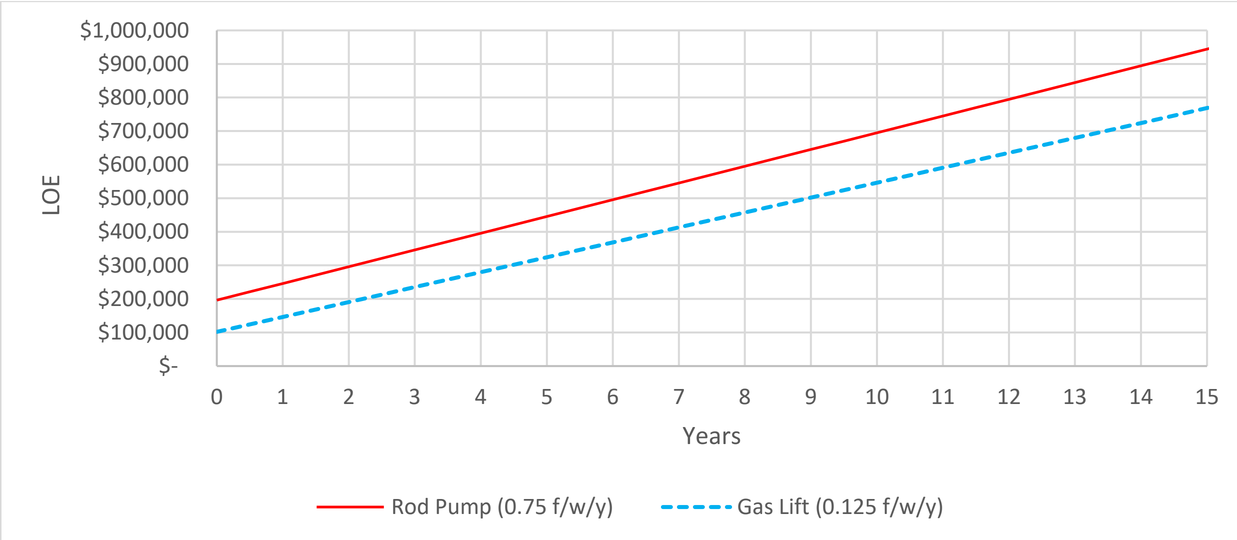

Figure 2: Above chart shows the significant difference in yearly LOE costs for horizontal gas lift and horizontal rod pump wells at their perspective average failure rate for the asset

Figure 3

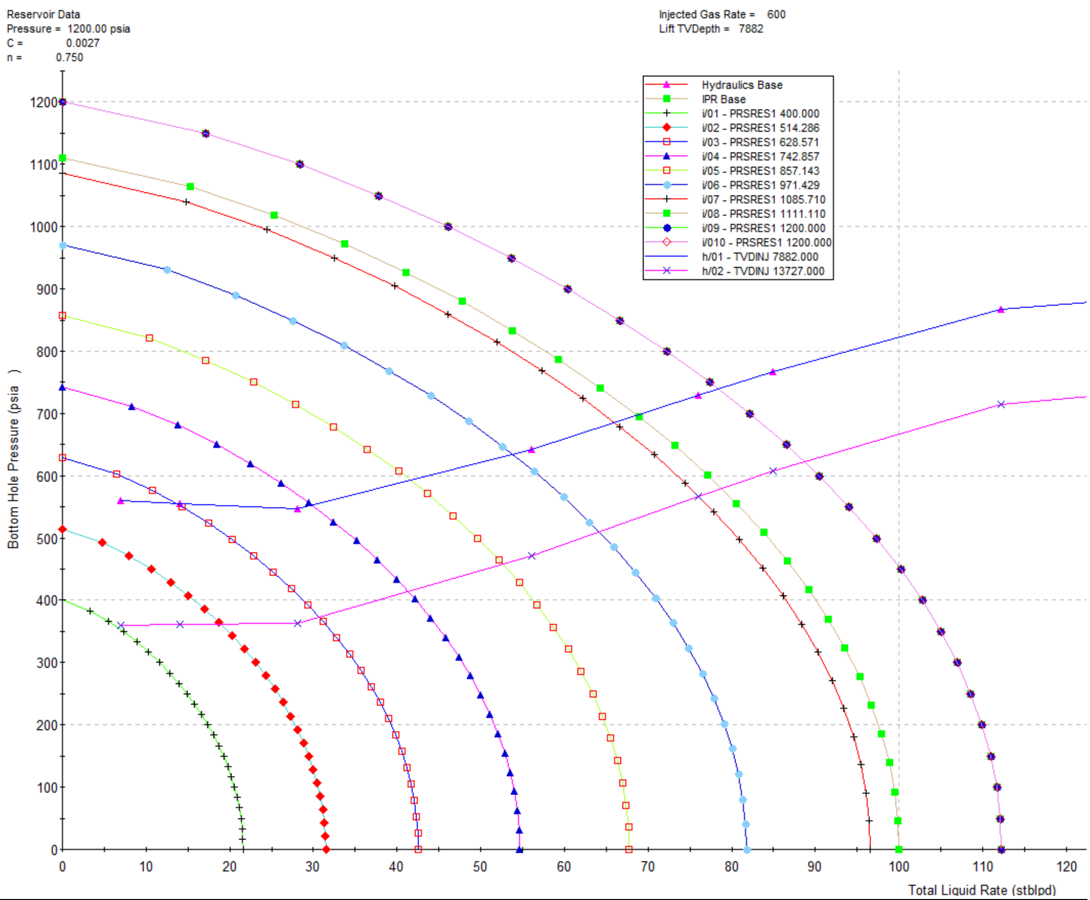

Figure 3: Simulated nodal analysis comparing conventional and deep gas lift in one candidate

Figure 4

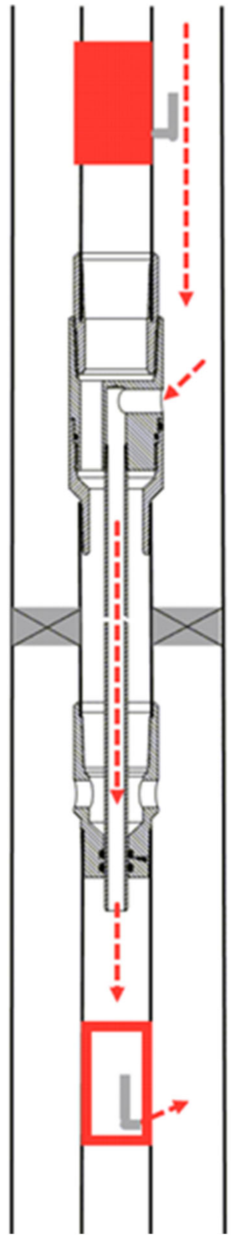

Figure 4: Sample crossover packer schematic

Figure 5

Figure 5: Sample subs used in pilot downhole equipment design

Figure 6

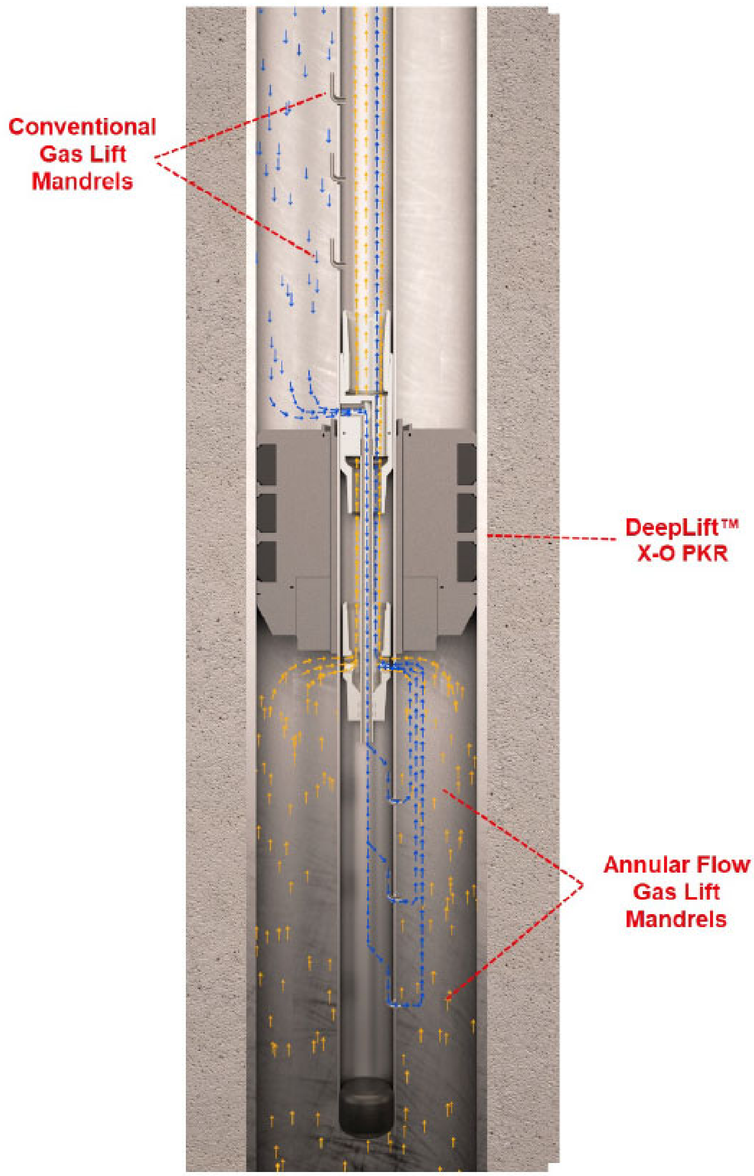

Figure 6: Theoretical gas flow path with new downhole equipment configuration

Figure 7

Figure 7: Downhole material cleaned out of the lateral

Figure 8

Figure 8: Downhole material cleaned out of the lateral

Figure 9

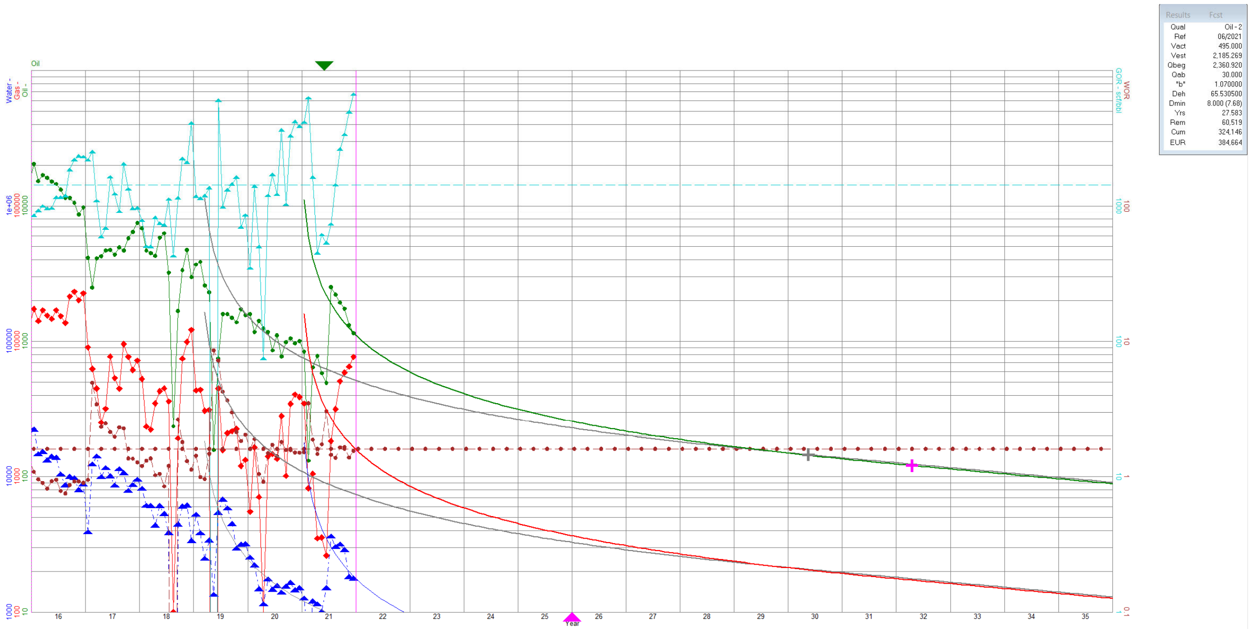

Figure 9: Candidate 1 production curve – 1 mile lateral, lower GOR of two candidates

Figure 10

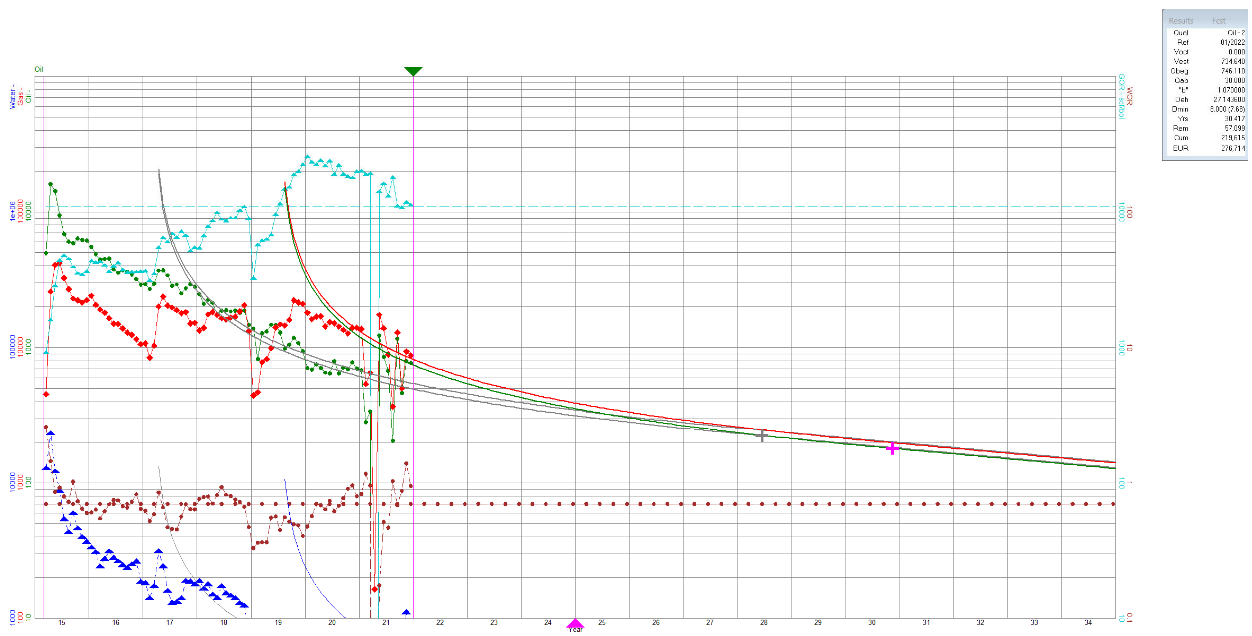

Figure 10: Candidate 2 production curve – 1 mile lateral, higher GOR of two candidates