REDUCING ROD PUMPS STUCK IN TUBING IN THE HIGHWAY 80 FIELD

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ABSTRACT

Insert rod pumps stuck in tubing increases well servicing events driving up cost and safety risks. The Highway 80 area reviewed the number of pumps stuck in tubing conditions they had from 2010 to mid-way through 2017. There was a total of 825 pumps that could not be pulled with the rods and tubing to retrieve the pumps. Pioneer Natural Resources chose to use a rubber fin element below the discharge of their insert rod pumps to prevent lodging from occurring. With this change, a reduction in pumps getting stuck was achieved, but approximately 10% of their pumps continued to get stuck in the tubing. Another design change was implemented in the third quarter of 2017, Harbison-Fischer installed their Brush Sand Shield on all of Pioneer's insert pumps, and they continue to do so till this day. This paper will discuss the early results of approximately 18 months since the first Brush Sand Shields were installed. We will compare the pumps that were pulled due to being stuck in the tubing with and without the design change since the implementation. Our goal is to continue to review the trend to see if positive results occur. We have calculated that the additional cost of pulling tubing is greater than 50%, more than if the pump can be retrieved with the rods. We will track the data and present it again in 2020.

INTRODUCTION

Sucker rod pumps are the most popular artificial lift method in the world. Due to their toughness, ease of automation, energy efficiency, and having the highest drawdown capability.

BACKGROUND

Conventional API rod pumps can be used in nearly any well, with fluid volume and depth being the main limiting factors. There are two basic types of sucker rod pumps -insert and tubing. The insert rod pump's design allows it to be run into and retrieved from the well with the sucker rod string. The tubing pump barrel assembly must be installed on the tubing. The most popular insert pump design is a bottom hold-down pump due to its ability to be installed into greater depths than a top hold-down pump. A bottom hold-down pump disadvantage is its propensity for it getting stuck in the tubing. The pump's discharge is at the top of the pump, and any particulates produced in the well fluid will fall in the barrel/tubing annulus, building up on top of the hold-down assembly. To retrieve the pump, the tubing must be pulled at a much higher expense than just pulling the sucker rods. Some additional issues are: the rods will need to become disconnected from the pump in some manner, or they will need to be pulled along with the tubing; this is commonly known as a stripping job.

DISCUSSION

There are modifications applied to bottom hold-down insert rod pumps to lower the occurrences of them from becoming stuck in the tubing. Placing a barrier right below the insert rod pump's discharge will reduce the number of particulates from falling into the barrel/tubing annulus and will reduce pumps from getting stuck in the tubing. Going back more than 20 years Pioneer Natural Resources had experienced many stuck pumps and started using what is referred to as a rubber fin element below the discharge of their bottom hold-down insert pumps. Although the improvement was not documented, we believe there was a reduction of pumps stuck in the tubing. Pioneer Natural Resources converted to the Harbison-

Fischer Brush Sand Seal in 2017, giving us an opportunity to document how this design change performed.

PUMPS STUCK IN TUBING

When pumps are stuck in the tubing, there are other costs and concerns that should be mentioned. When the pulling unit initially tries to unseat the pump, and it is stuck, there is a possibility that the sucker rod string could be damaged. Operators of pulling units must be properly trained to not exceed the yield strength of the sucker rods. To avoid a stripping job, the operator will attempt to disconnect the sucker rods from the insert pump. If the "clutch" on the rod pump is in good shape, the rods can be "backed off." Meaning at the surface the crew will rotate the rods counter clockwise and hope the sucker rods disconnect from the pump. A more accurate and safer way is to have installed an "on and off tool" at the pump when the pump was run into the well. This tool allows the rod string to quickly disconnect from the pump with just a quarter turn at the pump. Another, additional cost when pulling tubing with a stuck pump is containing the well fluid that is trapped above the pump. Many steps must be followed to ensure there is not any well fluid that contaminates the ground. As mentioned above, the least desirable way is to strip the rods and tubing out at the same time. This process is done by disconnecting the tubing and then disconnecting the rods and repeating this operation connection by connection until the pump is reached.

THE PROJECT

When the decision was made to convert to the Harbison-Fischer Brush Sand Seal, we wanted to make sure and capture the results to see if the additional cost was justified. We discussed that just one pump stuck in tubing would justify the cost of many Brush Sand Seals. Data recorded at the beginning of 2010 until the conversion to the Brush Sand Seal on August 1, 2017, was reviewed and concluded there were 8,010 well interventions during that time frame. In 10.2% of these interventions, the pump was stuck in the tubing. These 825 stuck pumps had an average day run of 974 days. There is a higher percentage of wells that have 2-3/8" versus 2-7/8" tubing in this field. For that reason, there was 633 stuck in 2-3/8" tubing and 192 stuck in 2-7/8" tubing. The drift of 2-3/8" tubing averages 1.901, leaving little room between the OD of 1.75" of the 1-1/4" RH and 1.875" of the 1-1/2" RX insert pumps. The rubber fin elements were used on both those designs, but the rubber fin element was not available for the 1-1/16" and the 1-3/4" RH insert pump, so they had no protection.

18 MONTHS OF DATA

There have been 1,380 well interventions since the implementation of the Brush Sand Seal August 1, 2017, through January 31, 2019. There were 163 or 12% of the 1,380 pumps pulled that were stuck in the tubing. 124 of these stuck pumps had the old-style rubber fin element, 27 did not have protection and 12 had the Brush Sand Seal. In 5 of these 12 with the Brush Sand Seal, the tubing would have been pulled either way because of a tubing leak. The number of wells pulled during this time that had a Brush Sand Seal installed was 164, and 12 or 7.31% of these were stuck in tubing. There were 72 of these 164 wells having Brush Sand Seals that previously had a history of pumps stuck in tubing pulled and were not stuck. 1,216 of the wells pulled had the rubber fin element or no protection, were also reviewed. 151 or 11% of these wells had the pump stuck in tubing. The team is also tracking the solid samples of all the pumps stuck in tubing. The samples showed to be 30% sand, 16% scale, 16% iron, 17% mixed, 2% salts, 1% Paraffin, and 18% unknown.

LOOKING FORWARD

We plan to continue monitoring the wells pulled when the pump is stuck in tubing or if they had a history of a pump getting stuck. We will compare the number of wells that have stuck pumps with the rubber-fin type seal versus the number with the Brush Sand Seal. We will also continue to track the percentage of pumps stuck in tubing per well intervention and compare that to the amount that we were having before the design change.

CONCLUSION

Well interventions that have a pump stuck in tubing add to the producers operating costs. There is also more significant exposure to injury and a possible environmental issue. Initial results point to a decrease in pumps stuck in tubing of the wells pulled that have a Brush Sand Seal. The authors understand that much more data will be needed to see if this trend continues. Future results will be shared when ample data points are available to update the information.