OPERATING AN ESP DURING A FRAC HIT

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ABSTRACT

Most frac hits are significant events with large pressure changes, followed by enhanced fluid flow volumes, frequently all water, then declining with increasing oil cuts at a level higher than before the frac hit event. This study examines how best to "ride through" the frac hit and how to manage electric submersible pump (ESP) settings for often rapid fluid rate changes during and after the frac hit event. Many of the wells studied experienced frac hits at different periods, so ESP operating setpoints are adjusted with changes in the load. The fluid rate increase was frequently much less than the wells' initial production and peaked after an initial pressure change. A pressure spike above the previous operating set point occurred approximately 14 days after the event. Then, the flow increased to its peak after another 6 days, on average. In the interim, where the well may experience pressure support from the frac, followed by increased fluids, some ESPs experienced lighter loading and tripped on underload condition settings. Evidence of slightly longer ESP runtimes on wells that have experienced frac hits is likely due to the ESPs running closer to their original parameters and reduced gas volumes. From the evaluation of mean times to failure after a frac hit and the Dismantle, Inspection, and Failure Analysis (DIFA) analysis of those failures, it is best to keep the ESP running during these events. After the wells' regular decline returns, that ESP drive parameter adjustments follow the new flow conditions. Some of these wells had multiple events, so the remaining run life is calculated after the first frac hit and not after the subsequent events. From a production standpoint, there is no advantage or disadvantage to shutting off the ESP during a frac hit. However, ESPs generally run longer with fewer shutdowns.

INTRODUCTION

The initial motivation for this frac hit study was to ensure that ESPs with permanent magnet motors (PMM) did not present an electrical safety hazard during the event. More specifically, would unplanned flow conditions, such as during the ESP installation, have negative impacts? However, the data observed that maximum pressure/flow due to a frac hit is much slower than that experienced during an ESP workover. During a workover, for example, rapid changes in fluid levels occur while installing an ESP. PMM auto-rotation safety concerns are addressed primarily by shunting techniques that forms a "magnetic lock" preventing motor rotation. This method can be enhanced with a continuous deployment monitoring system that provides observations during the ESP installation. The pressure change versus install depth during an ESP install is a much quicker process with resultant pressure changes than that observed from frac hits.

Observations in the study data set indicate a 0.22 psi/min pressure increase during the frac hits versus 22 psi/min on an ESP install with typical run-in hole (RIH) speeds of 20 ft/min and ordinary run rates during workovers. Therefore, safety concerns about PMMs with a possible frac hit during installation are not likely to be an issue.

ESP operating parameters are commonly adjusted as well productivity conditions change with normal decline over time. When a frac hit occurs with rapid and frequently large pressure and fluid flow changes, ESP settings require more significant changes and are somewhat backward to the normal flow of events. Therefore, it is important to understand how best to operate an ESP during a frac hit. From the dataset, some wells were shut down before the event as a measure of caution to protect the ESP. From a production standpoint, there did not appear to be an advantage or disadvantage to shutting off the ESP during the event, though generally it is best to minimize the number of ESP shutdowns. The ESP is not doing much work during flush production, and the pump may act as a choke. The sections below discuss how ESP operating points are affected during a frac hit.

OFFSET HYDRAULIC FRACTURE STIMULATION

How and why might offset hydraulic fracture stimulation treatments affect an offsetting horizontal wellbore? Hydraulic fracture stimulation treatment geometry is a function of hydraulic pressure, rock fabric, and natural fractures inherent in the rock strata. How fractures propagate and communicate may also depend on the perforation strategy employed. A stimulated wellbore may preferentially cause the created fracture propagation to trend in a particular direction. When injecting high-pressure fluids into a formation, the fractures created can extend beyond the intended zone and connect with existing fractures or natural faults. If the nearby wellbore is within the fracture propagation zone, the fractures may intersect, causing direct communication between the two wells described as a frac hit in this paper. The initial process of a frac hit is pressure interference from the injected fluids, increasing pore pressure in the formation and subsequently migrating towards the nearby wellbore. The increased pressure can destabilize the formation around the nearby well, potentially affecting wellbore integrity or altering the stress state of the formation.

Frac hits can lead to sand or proppant invasion into the nearby wellbore, plugging perforations or damaging production equipment. The increased pressure and fluid invasion can change the local permeability and reduce production efficiency in the offset well. The impact may also enhance the productivity of the nearby wellbore. This increased productivity is likely all water from the actual stimulation treatment plus solids from the injected proppant and previously settled solids.

Hydraulic fracturing creates localized stress changes in the rock (stress shadowing), which may alter the fracture geometry and propagation in the nearby well. These stress changes can cause fractures in the adjacent well to close prematurely or open in an unintended direction. Fracturing fluids and proppant can migrate toward the nearby wellbore, leading to operational challenges such as increased water cuts or sanding issues. In general, the initial production losses will more than recover over time.

The combination of fracture propagation, pressure interference, stress shadowing, and direct communication through fractures can negatively affect (however, positive impacts may also result) nearby horizontal wells' productivity, integrity, and operational stability. Therefore, well spacing should be considered, and careful fracture design is critical in multi-well pad developments.

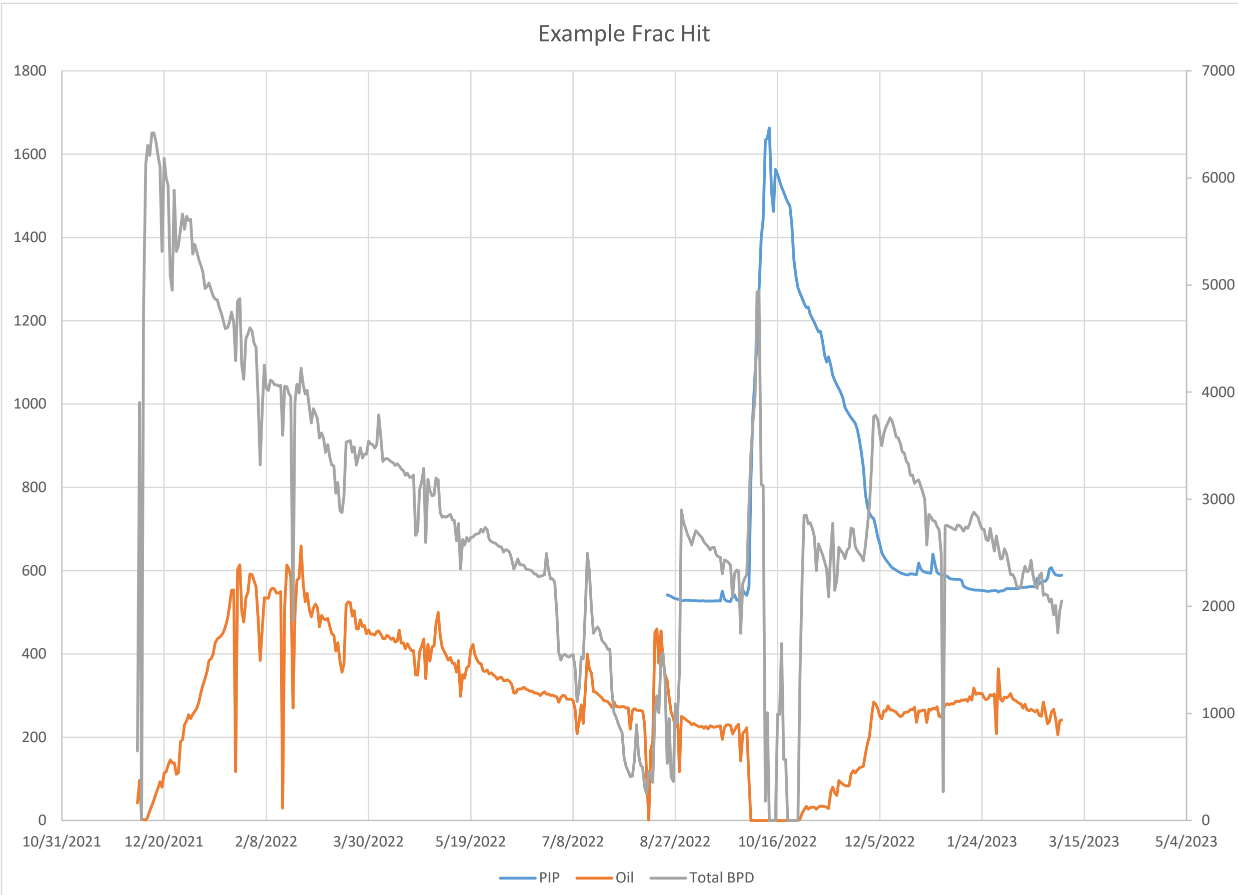
Several relevant topics are NOT covered in this paper: Drilling technologies have changed over time, such as the horizontal length of parent wellbore, for example, 1-mile laterals (2011-2015), 2-mile laterals (2015-2023), and 3+ mile laterals today may have some profound effects. Sand proppant size and strength have changed with time. Generally designed for abandonment, the operator may need to be able to increase proppant closure stress capabilities. The timing of frac hits may be planned as part of the drilling schedule or incidental to the program. The surveillance engineer may observe an increase in downhole pressure while maintaining a constant frequency on the ESP and may consequently suspect a frac hit, though the change could also be a tubing leak. Finally, refracs are relevant to unconventional wellbores, but these have (so far) not been done with an ESP still in the well, both in the studied dataset and in the industry in general.

GENERAL OBSERVATIONS

The frac hits seen in the 26 ESP wells in this dataset could be described generally as having normal production declines and then suddenly having a large increase in both downhole pressure and inflow. This is then followed by a normal decline from the new peak condition. In a few of the wells, rather than one significant event, there were multiple small events. It is much easier to manage ESP settings with these types of frac hits.

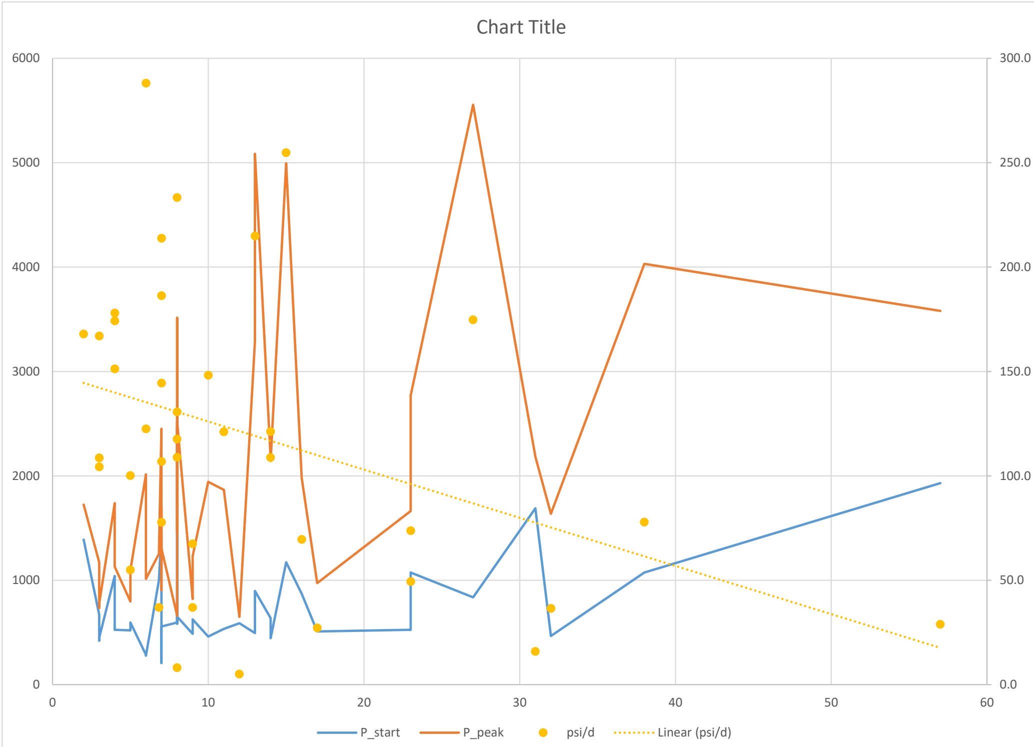
Overall, the dataset shows slightly longer ESP runtimes on wells that have experienced multiple frac hits. This is likely due to the ESPs running closer to the original sizing and having high water cuts and lower gas. Possible reasons for this finding are outlined by modeling actual conditions. From evaluation of times to failure after frac hit and dismantle, inspection, and failure analysis (DIFA), it is best to keep the ESP running during these events. It is good practice to minimize the number of ESP starts and stops to improve run life. After the oil cut and a normal production decline return, it is recommended to reset the ESP drive parameters to the new conditions, as is usually done when a well declines. Out of the 26 wells evaluated, 17 had an average failure rate of 80 days after the frac-hit event. Three of the 17 wells had multiple frac hit events, so the remaining run life was calculated after the initial frac hit. It was also observed that the average run life for the 26 wells was 422 days, which is about the same as the overall ESP run life in unconventional horizontal wellbores.

Figure 1. Examples Well, production trend before and after the frac hit.



The wells in this study had average initial production rates of 5,000 to 6,000 barrels of fluid per day (bfpd), declining to 1200 bfpd before the frac hit. On average, the frac hit increased flow to 2,200 bfpd after approximately 20 days. One observed "feature" was that the downhole pressure peak occurred prior to the peak in inflow peak, about 6 days on average. So, it was observed that first, the downhole pressure changes from ~800 psi and then rises to ~2,100 psi, spiking above the previous operating point after about 14 days. Then, after 6 days, the inflow increased to its peak. In the interim, where the well pressure increased but before fluids hit, some ESPs experienced lighter loading and subsequently tripped on previous underload settings.

Figure 2. Lower rate of change in intake pressure as overall frac pressure increases.



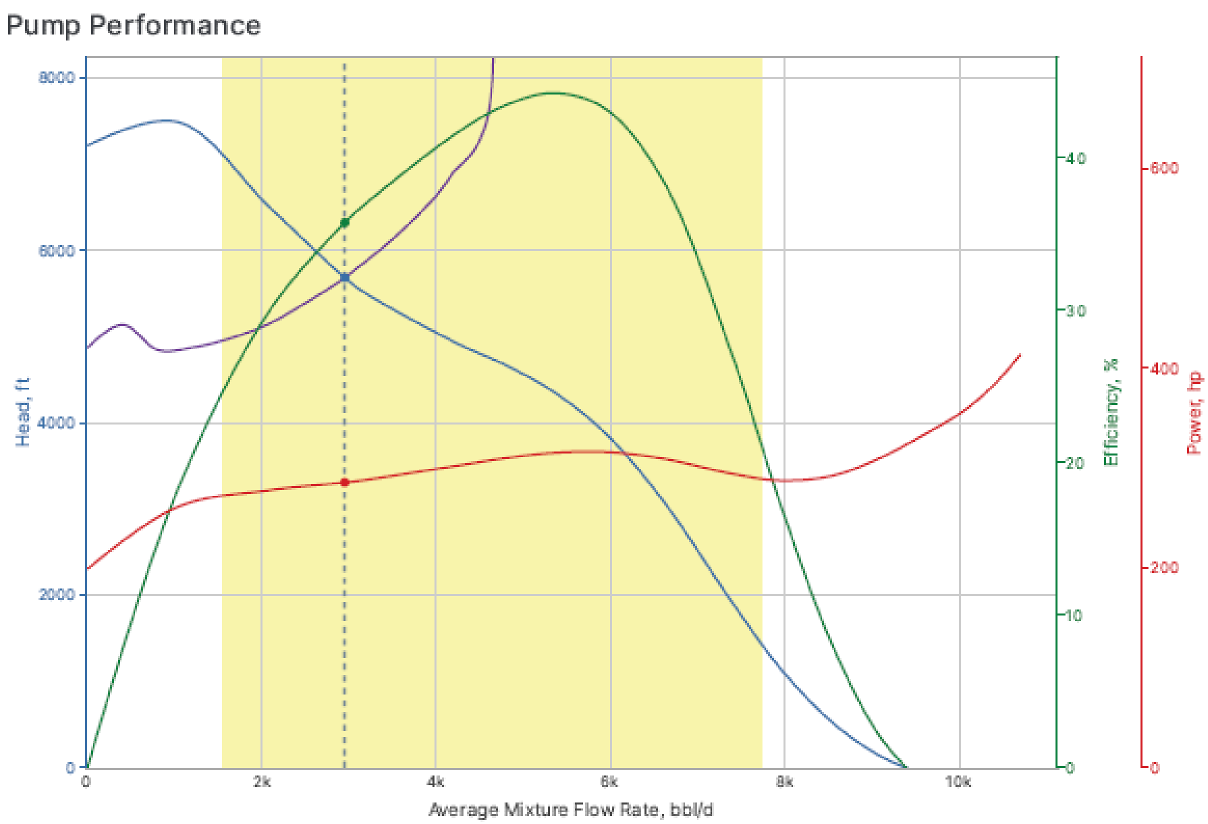
In the dataset, some outlier wells experienced slow, multiple frac hits. These outliers did not experience 100% water cuts but appeared to have some EOR benefits. Ambient well fluid temperatures showed a slight increase, roughly between 2 to 4 degrees F, possibly as a result of change in overall fluid composition as well as increased flow rates.

ESP MATCH OF CONDITIONS (MOC)

Simulation software was used to match operating conditions (MOC) or history match (HM) data, notably the original ESP parameters. One benefit of this modeling is to look at pressure build-up on the occasional shutdowns of sufficiently long durations, as shown in Figure 3. From these events, it is possible to predict adjusted reservoir pressure, P_r, (assuming PI does not change) to match conditions to the pump operating point and motor load. In general, motor amperage from the beginning of a frac hit to the peak was less than 1% higher, so it was negligible, signifying that motor overload was not an issue. Similarly, the peak inflow rate was, on average, 16% less than the rated pump's best efficiency point (BEP), suggesting that severe upthrust conditions are also not a concern. This issue was not identified in the DIFA's of the dataset wells either.

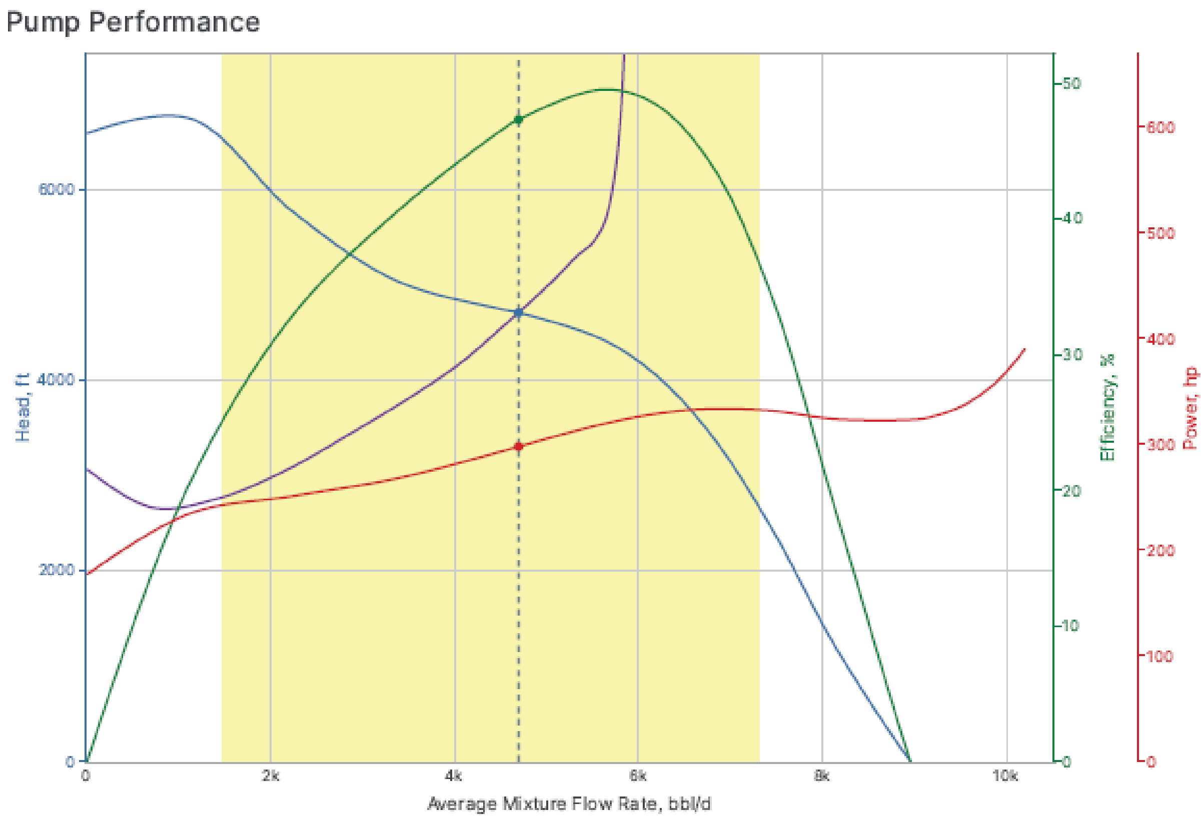
Figure 3. Pump Intake Pressure drop over time.

Figure 4. MOC Pump with pressure support, prior to a frac hit.



As previously mentioned, there is an approximate 6-day interim when the well experiences pressure support from the frac hit, but before fluids hit so the ESP will be lightly loaded and may trip on underload settings. Some operators slowed the ESP's down in anticipation of the frac hit to help deal with the loss of load.

Figure 5. Peak frac hit model, 5800 pump at 56 Hz.



Also noted, there frequently was a slight benefit in ESP run life which appeared to be a result of flow conditions closer to the original design pump curve. This outcome provides justification to keep the ESP running at its best efficiency point (BEP). Run life was somewhat negated due to high solids pump wear as observed in the DIFA's.

From the evaluation of ESP time to fail after a frac hit and DIFA's of those failures, it is best to keep the ESP running during frac hit events. After the well's normal decline returns, it is recommended that the drive parameters be reset to the new conditions. As noted, some of these wells had multiple events, so the remaining run life was calculated after the first frac hit. From a production standpoint, there does not appear to be an advantage or disadvantage to shutting off the ESP during a frac hit. However, ESPs generally run longer with fewer shutdowns.

If there is a slight emulsion peak at a specific water cut range, then it may be advantageous to speed up the ESP. Knowledge of an emulsion peak may allow the ESP to follow the natural drawdown rather than slowing down through "trouble spots". It is also important to note that frac hit wells may experience an emulsion peak twice. The emulsion issue is most likely with gas-liquid-ratios (GLRs) above 1,200 and water cuts (especially in shale reservoirs) of 50% - 70%. This is a small effect and can be complicated with the influence of natural gas and solids. Another way to evaluate this potential impact is to look for trends where pump horsepower does not exactly follow total fluid and observe how water cut, gas, and other parameters are changing during these transitions.

It is also possible that an increase in load is due to solids production resulting in higher density fluid. The solids could come from the offset frac or from corrosion control issues such as iron oxide, where the increased flow rate and water enhances more iron precipitation. The tendency by many operators is to slow down the ESP but this can lead to deadheading the pump, shutdown and solids fallback that ultimately cause the ESP to seize. Maintaining or increasing speed is often the best strategy, similar to the peak emulsion condition.

CONCLUSION

Unconventional ESPs are designed for production wells experiencing large fluid inflow fluctuations, so they can easily handle frac hits. The original motivation for studying the effects of frac hits on ESPs was electrical safety, with a PMM system installed. However, this paper found that frac hits are relatively slow processes and do not generally increase that hazard. Instead, the findings suggest the need to closely monitor ESP settings to ensure the new inflow conditions do not result in an immediate shutdown of the ESP. The frac-hit wells in the study dataset had higher overall inflow, water cut, and reduced gas volumes, which is preferable for operating a centrifugal pump on its normal operating range. ESPs also lasted slightly longer than wells not frac hit. Operationally, ESPs perform better with higher inflow rates experienced from frac hits, so the primary concern is ensuring correct ESP settings for the changing flow conditions and minimizing shutdowns.

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