NOVEL ROD PUMP CONTROL FOR WELLS WITH COMPLEX PUMPING CONDITIONS

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ABSTRACT

When operating rod pumps, it is important to match the volume displaced by the pump to the inflow from the reservoir. By doing so, downhole pressure is minimized, thus maximizing production, while keeping mechanical damage and power consumption to a minimum. Various devices such as time clocks, pump-off controllers or variable frequency drives have been adopted in the industry to achieve this goal. While they operate based on different principles and might be suitable for different types of assets, all of them seek to curtail the volume displaced by the pump to achieve pump off while avoiding fluid pound.

However, the precise tuning of these devices can be challenging and a lot of setpoint management is often done on a customary basis rather than from rigorous analysis. For wells exhibiting simple pump-off situations, this is adequate as the entire production can be realized at near optimal pump fillage. However, many wells (for instance modern horizontal ones with long laterals) exhibit more complex flow patterns, effectively implying a tradeoff between maximizing production and avoiding damaging pumping conditions. When this happens, the optimal operating regime will depend on the precise quantification of the trade-off, commodity prices and the specific circumstances of each well.

In this paper, we present empirical data showing that such instances are not mere anomalies, but in fact frequent cases. Furthermore, we introduce novels approaches in terms of data collection and control algorithms allowing us to quantify those trade-offs and maximize well flowrates.

CONTINUOUS, HIGH RESOLUTION DATA ACQUISITION AND PROCESSING

Using 5G networks and advanced on-device compression algorithms, our system can stream continuous, very high resolution (*eg* 100 Hz) data back to our centralized cloud system, including well-head position and rod pump loading. Using these signals, our system automatically generates dynacards for every single stroke of the pumping unit. A machine learning algorithm then automatically processes these cards to generate pump fillage results and diagnose mechanical issues. This stroke-by-stroke data is extremely valuable as far as our system's capability to model the behavior of a given well and optimize its operations.

The simple, standard model describing the functioning of a well is as follows: fluids flow into the casing from the reservoir and liquids accumulate at the bottom of the casing. When the pump is running and the liquid level sits above the pump, the strokes are full; conversely, when the liquid level reaches the pump intake, pump fillage goes down to a value matching pump slippage plus reservoir inflow.

Therefore, when the pump turns on following a downtime, we expect to observe a series of high fillage strokes followed by a brutal collapse of the pump fillage signaling that the well is pumped off. Such a response is shown on Figure 1; this chart displays the pump fillage over time for every timer cycle of well over 24 hours. While it is known that more complex behaviors such as gas interference exist, traditional pump-off controllers are effectively predicated on such a model. Indeed, under this assumption, picking a conservative fillage threshold with limited information regarding the individual well is adequate to maximize production while minimizing mechanical damage.

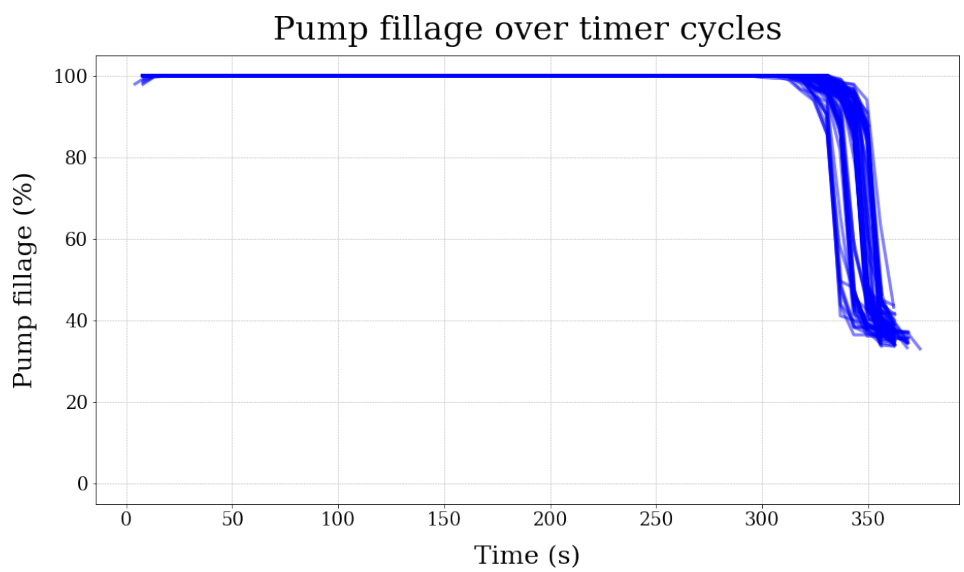

Figure 1 – Standard pump fillage profile when a well turns on

However, with exhaustive, high-resolution data available, one can revisit how closely this model matches empirical well behaviors. The first issue that arises upon investigation are scenarios where the transition from a full to an empty pump takes place more gradually. Imperfect liquid/gas separation above the pump could account for such behaviors. A moderate case is presented on Figure 2, while Figure 3-4 showcases more extreme situations.

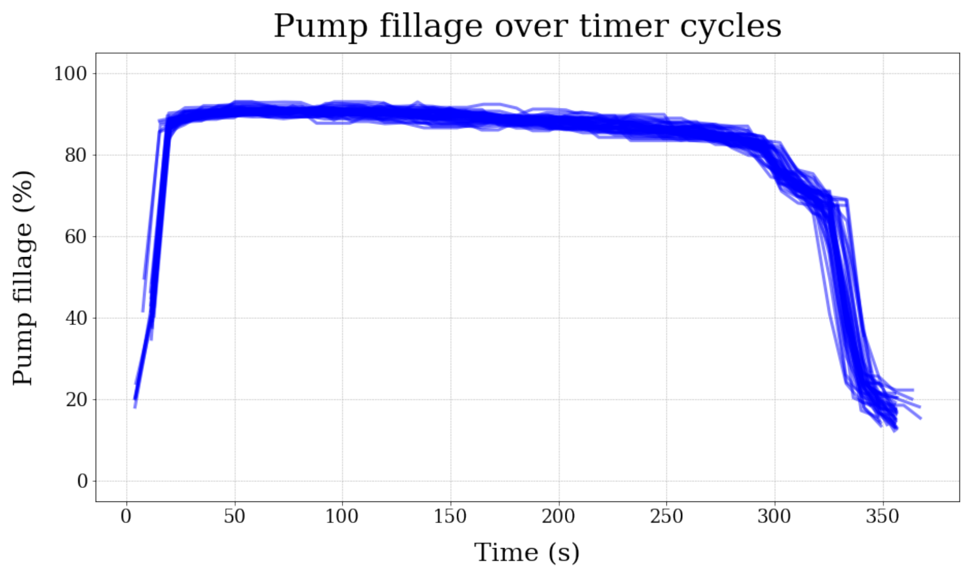

Figure 2 – Moderate pump fillage decrease before pump-off as casing liquids deplete

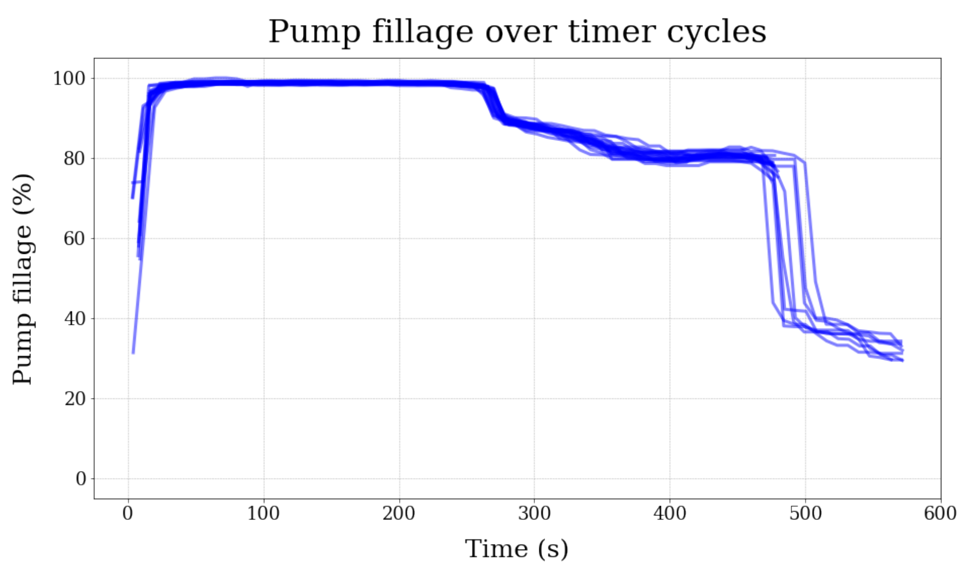

Figure 3 – Staged pump fillage decrease as casing liquids deplete

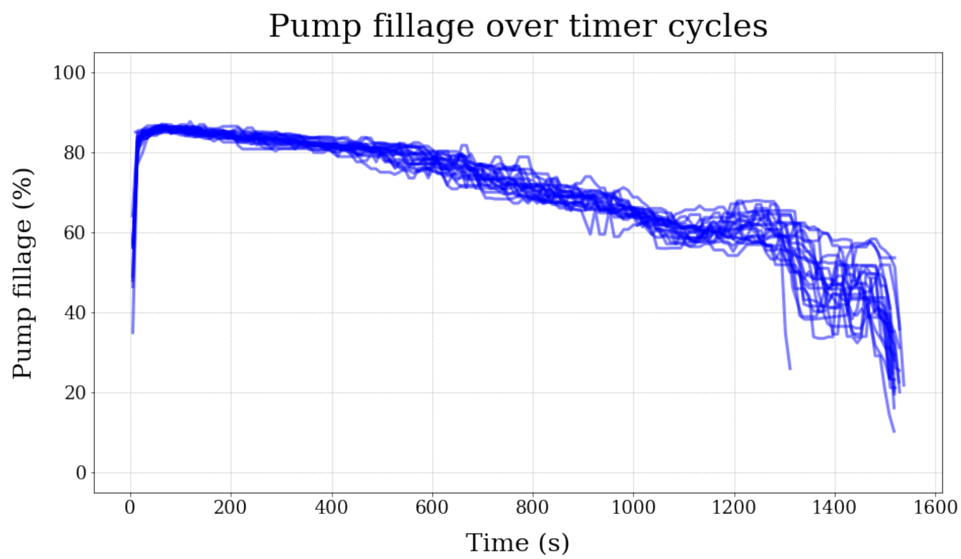

Figure 4 – Progressive pump fillage decrease as casing liquid depletes, no distinct pump-off discernable

In such cases, there is a trade-off between maximizing production and avoiding bad pumping conditions. Fortunately, having access to high resolution data, it's possible to use AI algorithms to optimize the economics of the well.

Other challenging cases are situations with inconsistent gas inflow where large but transitory drops in pump fillage do not indicate pump-off (see Figure 5). There again, applying generic control setpoints without more advanced algorithms results in curtailed production.

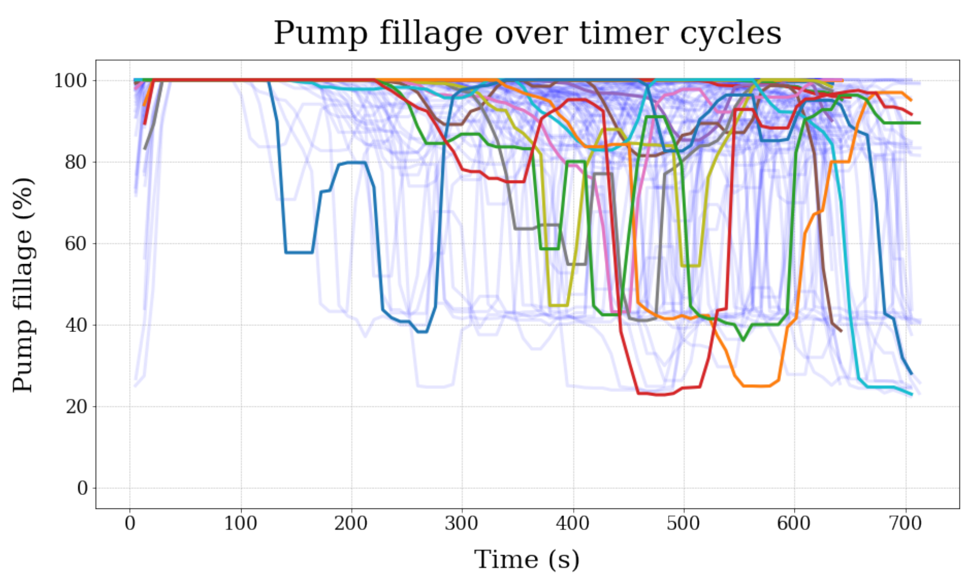

Figure 5 – Inconsistent gas inflow to the pump

Finally, some wells display pump fillage profiles that are difficult to reconcile with any variations of the standard inflow model we described above *(eg* Figure 6). In such cases, it is especially attractive to build unique, data driven models to optimize the well's performance.

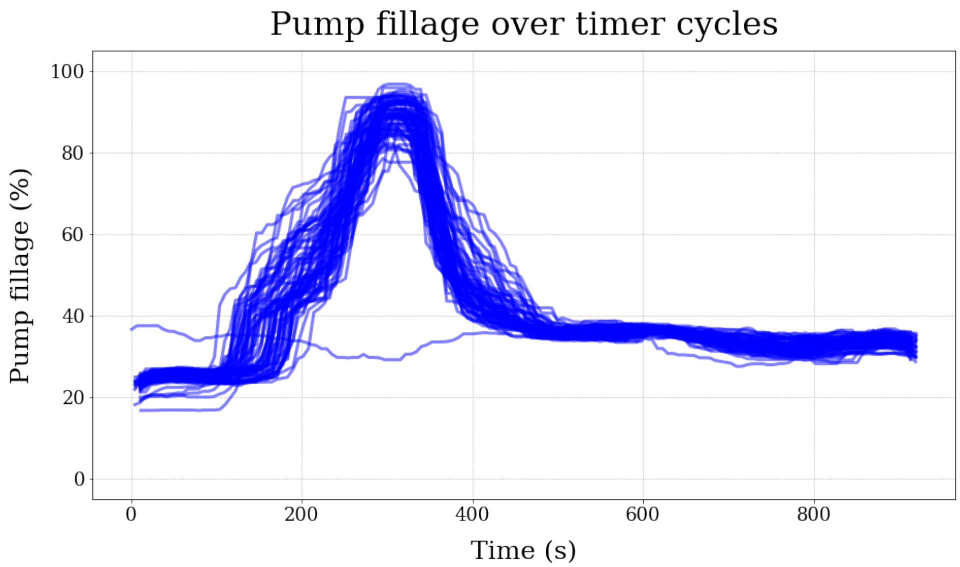

Figure 7 – Non standard pump fillage profile

CASE OF SLUG FLOW IN HORIZONTAL WELLS

An important class of wells that proves particularly difficult to optimize are wells exhibiting slug flow patterns. Slugging is an adverse flow pattern that can emerge in bi-phasic gas-liquid flows in the presence of altitude changes of the flow conduit (pipes, risers, wellbores, etc.). When flowrates become large enough, an instability appears where the liquid intermittently restricts gas flow, leading to the buildup of intermediate high pressure gas pockets that are eventually flushed as a slug until the pressure drops to a point where gas stops flowing again. This type of behavior is well attested on offshore risers or gas lift systems.

Based on our data, it turns out that this type of issue is extremely prevalent among horizontal wells equipped with rod pumps. Figure 8 shows a recording of the pump fillage for every stroke of a well over two weeks. In this example, the well is running continuously, but the pump fillage signal shows a clear oscillatory response. This type of behavior is known as a limit cycle in systems theory and is characteristic of certain nonlinear dynamical systems. Figure 9 displays similar data for a well equipped with a pump-off controller. As can been seen, the instability is not solved by the controller.

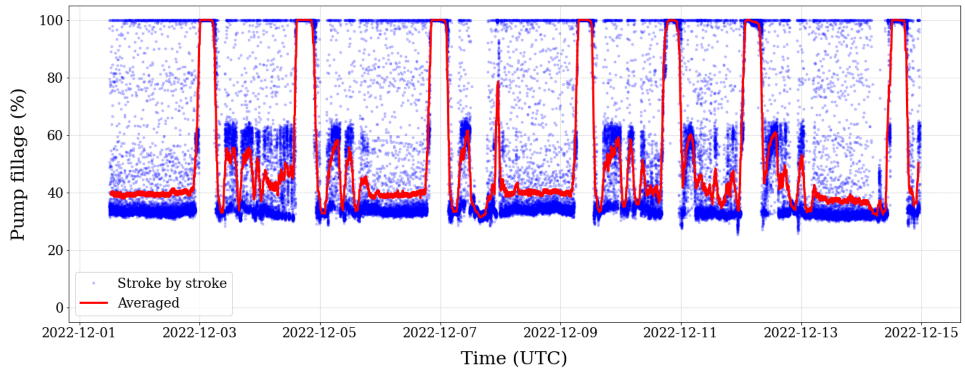

Figure 8 – Fillage of a rod pump running continuously on a horizontal well

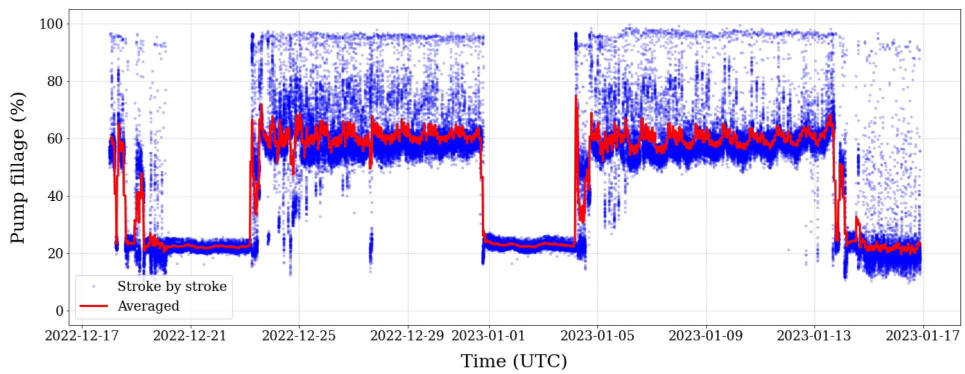

Figure 9 – Fillage of a rod pump controlled by a pump-off controller on a horizontal well

Thanks to this detailed information, we can create a controller that learns the dynamic pattern of the slug to stabilize it. As a detailed example, we consider the case of a VFD-controlled rod pumped horizontal well drilled & completed in 2015, 4,500 ft TVD with a 5,500 ft horizontal section. Field operators reported highly inconsistent pump behavior backed by Echometer dynamometer surveys displaying full and empty stokes a couple hours apart (see Figure 10). Despite their best efforts, the operators were unable to optimize the well to suppress this behavior.

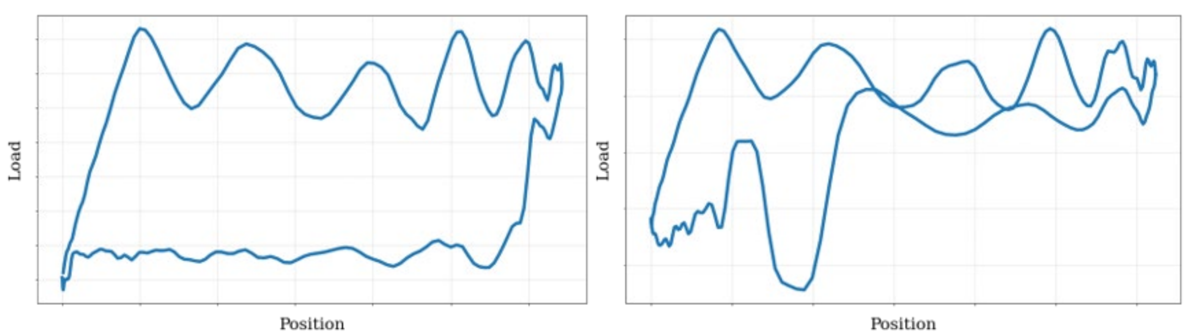

Figure 10 – Empty and full dynacards on a slugging well

Upon installing Acoustic Wells' continuous monitoring and optimization system, it became apparent that the well was experiencing severe slugging behavior. In this specific instance, Figure 11 displays 5 days of recorded stroke-by-stroke pump fillage. As one can see, the pump displays a periodic pattern over 12 hours. While pump fillage averages 76%, it is in fact swinging wildly, peaking at 100% and falling as low as 40%. In particular, half of all strokes show fillage lower than 80%, a typical operational rule of thumb to avoid damaging the equipment.

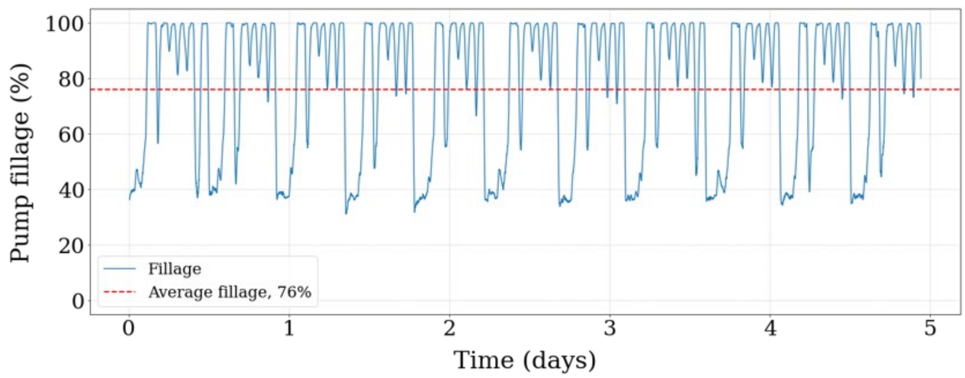

Figure 11 – Pump fillage pattern over 5 days on a slugging well

We are able to set up a controller that learns the dynamic pattern of the slug to stabilize it. The result of this process is detailed on Figure 12. After a learning period of 7 days, the slug is gradually stabilized, leading to a new flow pattern where pump fillage averages 90% and never goes below 80%, thus considerably reducing pounding and damage to the rod string. Additionally, the new control regime resulted in a 30% reduction of pumping unit runtime while also maintaining constant production (tested at 43 Boe/d before, and 45 Boe/d after the intervention), leading to an additional increase in meantime between failures as well as corresponding electricity savings.

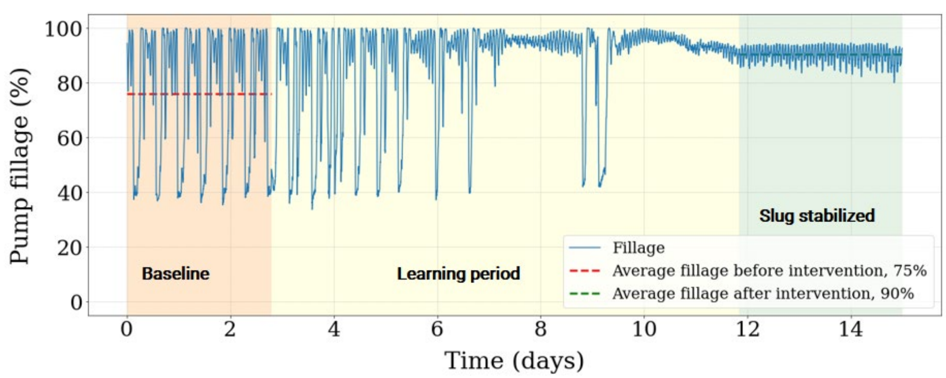

Figure 12 – Stabilization of the slug by controller

<u>CONCLUSION</u>

In this paper, we presented empirical evidence outlining the variability and the complexity of the pump fillage profile of rod pump operated wells. We show that it is not possible to operate those assets optimally without building a system able to tailor its response and optimization strategy to those individual empirical responses.