DYNAMIC PUMPING UNIT CONTROL USING VARIABLE FREQUENCY DRIVES AND EDGE AI MODELS

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0. Abstract

Through the operation of a rod pump, stress oscillations can be observed in the rod string, most prominently at the beginning of the upstroke and downstroke phases. This dynamic phenomenon has several adverse consequences on the well and associated equipment. The load in the rod string is drastically increased at the start of up/down strokes and is a primary contributor in the limited service life of the rod string itself; moreover, in these scenarios, the change in plunger velocity is also higher thus increasing erosion and wear on the pump itself in addition to additional stress on the gearbox and the pumping unit itself.

It is well known that reducing a unit’s speed (stroke-per-minute or SPM) will reduce the severity of these stress oscillations at the cost of production. Simple once-per-stroke intra-stroke speed changes are often used today on long-stroke pumping units (such as rotaflex units) to reduce equipment wear at the top and bottom of each stroke as well as sometimes in wells with gas issues to minimize the pounding/buckling effect on the rod string during the downstroke motion.

In this paper, we present how multiple dynamic intra-stroke motor speed adjustments can reduce stress while also increasing production. We also show how the motor speed can be automatically computed to obtain a system that dynamically adapts to any well.

Examples of the system’s ability to reduce stress while maintaining or increasing production are shown on a sample of various wells across the US. We show how a theoretical control model was developed, and the results of its implementation through AI models running a variable frequency drive (VFD, or variable speed drive/VSD) via a machine-to-machine connection.

This paper shows real-world examples of how AI can be used to build flexible well control models which bring a materially positive impact. The result is a system that can be used on any rod-pumped VFD-powered well and will deliver optimal production at minimal wear.

1. Telecom and data structure of high-end edge + cloud infrastructure

The ability to control a well (or any machinery) in a very detailed and advanced way is not compatible with typical legacy SCADA infrastructure. We present here a novel oilfield automation system that transcends traditional SCADA limitations through innovative technology integration. Unlike conventional systems that are hampered by poor data resolution, high operating costs, complex implementation, and isolated data streams, the solution presented here leverages modern networking, AI, and computing advances to transform field operations.

We utilize 5G networks (with satellite capabilities forthcoming) to enable high-speed, continuous data streaming from wellheads and associated facilities & infrastructure via either our own devices or plugging into existing SCADA equipment via MODBUS. One of our standard data streams enables stroke-by-stroke monitoring of rod pumps. Through our sophisticated edge-cloud architecture, lightweight edge devices run optimized models for immediate local decisions while simultaneously transmitting data to cloud infrastructure for comprehensive analysis and real-time recomputation of models. This two-way communication channel enables constant refinement of edge models based on fieldwide insights, creating an adaptive system that continuously improves its performance.

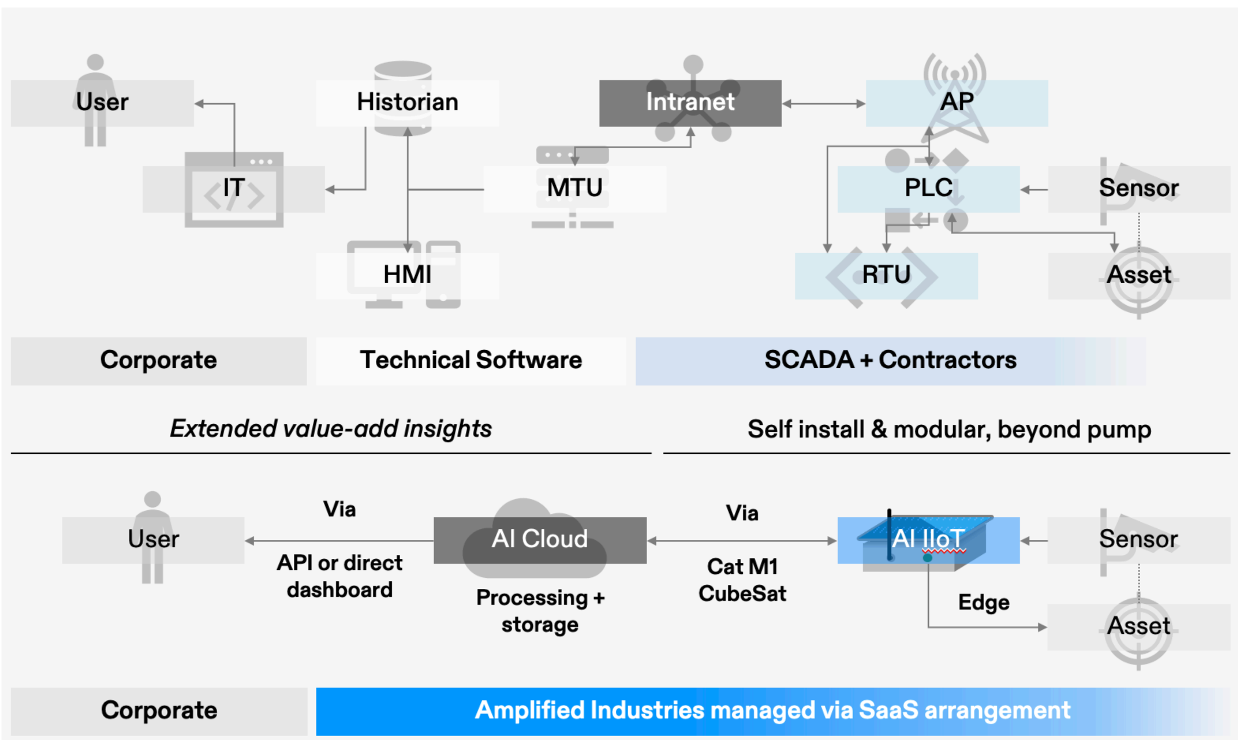

Figure 1 – Legacy Scada data flow vs novel approach

Our integration of simultaneous high-resolution wellhead data streams (with data from associated infrastructure) and MODBUS polling data from VFD/VSDs enables powerful applications beyond basic remote speed control, including intra-stroke analysis, surface leak detection, and virtual flow metering to allocate production across multiple wells sharing a tank battery. By fusing multiple data streams (tubing pressure, dynacards, tank levels, current, acceleration, etc), we are capable of providing actionable insights without overwhelming users or requiring dozens of user-input fields that are traditionally very error-prone. On rod pumps, the use of machine learning algorithms makes several traditional sensors irrelevant, such as crank position sensors or motor RPM sensors, reducing hardware requirements and overall barrier to entry.

Our solution ultimately delivers significant operational improvements; at the field level, we typically see a 5-10% increase in production along with a 30-50% reduction in electricity usage in addition to extending equipment life through minimized mechanical wear and optimized pumping regimes. Additionally, this framework opens the door to novel cutting edge applications such as the one presented below.

2. Analyzing the effect of SPM on rod loading and pump life

A rod pump well operates through a reciprocating motion that drives fluid extraction from underground reservoirs. At the surface, a beam pumping unit converts rotary motion from a prime mover into vertical oscillation of a polished rod. This rod extends downhole through the tubing string, connecting to a sucker rod string that activates a subsurface pump assembly.

As the rod travels upward, the traveling valve within the pump closes due to the pressure of the fluid column above it, while the standing valve opens from the pressure differential, allowing reservoir fluid to enter the pump barrel. During the downstroke, the standing valve closes to prevent backflow, while the traveling valve opens, permitting fluid above it to move upward through the pump. This valve commutation sequence creates a piston-like action.

Because of its slenderness, the rod string behaves like a spring. When there is a sudden change of plunger velocity, a large stress wave propagates across the rod string and is visible on the surface card as oscillations. This effect is exacerbated when the well is deep, deviated, or when the stroke speed or SPM is increased.

As the SPM of a well is increased, the plunger’s changes in velocity increase in scale, which creates larger and larger stress amplitudes. Vice-versa, at increasingly slow SPM the surface card becomes flatter and flatter, eventually looking like a perfect parallelogram (in the case with no significant rod-tubing friction).

While the average upstroke load will also marginally increase with SPM due to viscous liquid friction, the dynamic oscillation dominates and is the killer effect in wells, responsible for most rod parts at high SPM.

In Figure 2, which was acquired on a 8,000’ TVD well, the peak-to-peak loads increase by over 33% when doubling the speed from 3 to 6 SPM. This effect is even more pronounced at higher SPM, for example going from 6 to 9 SPM.

To avoid early failures, most VFD-run wells are set with a conservative maximum speed. This means that either some production potential is left untapped, or that a vastly oversized pump, rod stroke, and surface machinery have to be used to pump the desired volume at a low speed. The extreme can be seen in the use of long-stroke pumping units (such as rotaflex) which are typically run at 2-3 SPM and have an almost perfectly flat surface card. The lower failure rate is offset by a very high upfront capital cost.

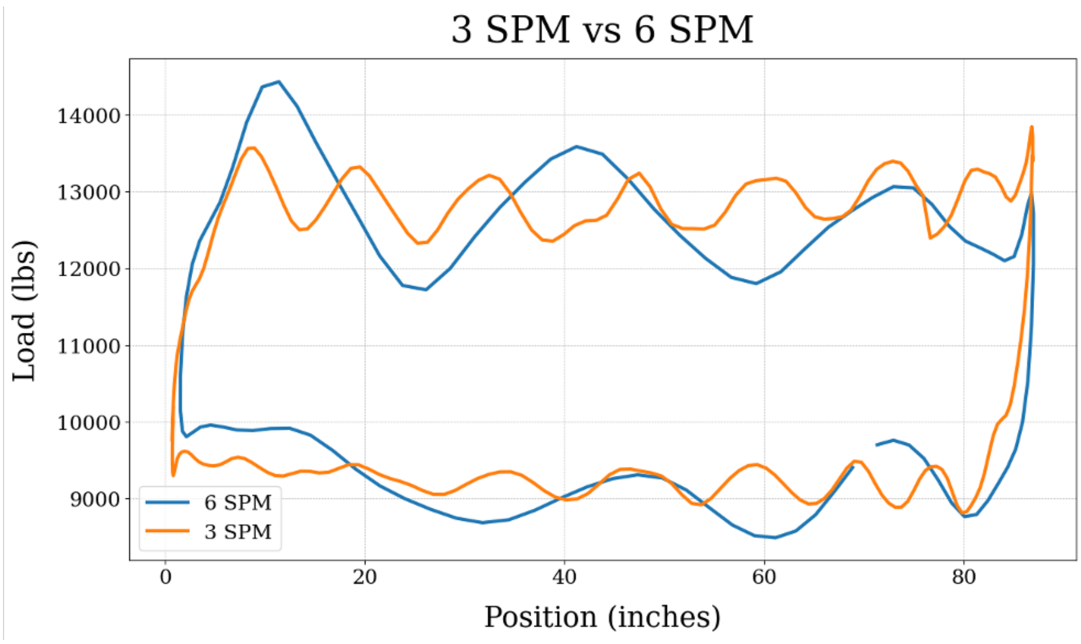

Figure 2 – Effect of SPM on Max and min rod loading

Rod string life is also often limited by the material fatigue life. In the case of a rod made of steel, the fatigue life is exponentially reduced based on the difference between the maximum and the minimum load seen during a pumping cycle. Since increasing speed increases the maximum load and at the same time decreases the minimum load, the material life is greatly reduced when a well is sped up. The well in Figure 2 has its fatigue life reduced by a factor of 6 when going from 3 to 6 SPM. That means it will theoretically experience a rod part significantly earlier with a life 12 times shorter.

For example, most newer Permian wells with a vertical section of 8,000’ to 10,000 have a rod string that is already highly loaded by design and allows very little leeway for a straightforward SPM increase.

3. How physics and an AI model are key to accurately & efficiently modelling a well stroke

Using classical physics, we have fully modeled a rod pump well. The now industry-standard wave equation allows us to calculate the stress at any point in time and at any depth along the rod string, while also calculating the plunger velocity profile. The unit geometry is a known entity, so basic kinematics allow us to calculate the relationship between motor RPM and plunger velocity vs. time, or motor RPM and load at every depth vs. time.

Integrating that physical model with a sophisticated data ingestion and processing layer, we can now analyze every stroke of the well while calculating the ideal velocity profile for the next stroke.

The ML/AI layers are introduced where the theoretical physical model has to be reunited with real-world physical constraints. For example, too strong accelerations are not allowed to reduce gear loading, while deceleration rate is highly dependent on the position throughout a stroke, well balancing, and VFD propertie, such as the availability of regen or braking resistors are available.

After a specific training phase, the system can establish the tuning potential of a well and generate specific VFD commands dozens of times per second based on the desired user outcome. While today we have focused on reducing loads or increasing SPM at constant loads, it is possible to generate a specific speed profile to reduce the peak or overall power consumption for the well, or to minimize the well’s sensitivity to specific mechanical considerations. The velocity profile can also be used to minimize the number of overvoltage alarms on VFD’s with no regen or limited braking resistors. The system is compatible with multiple drives and is vendor-agnostic.

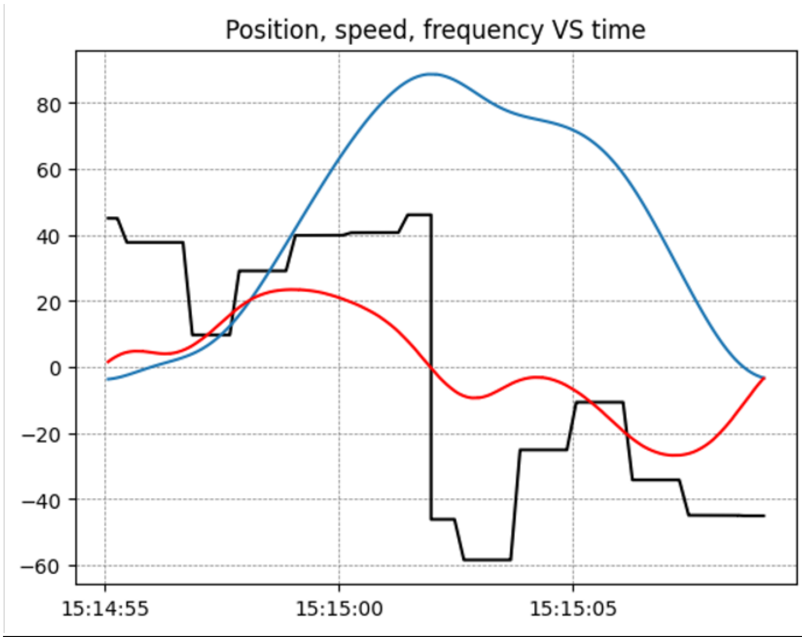

Figure 3 – Wellhead position (blue), velocity (red) and motor RPM requests (black). Negative RPMs illustrate the downstroke section

In Figure 3, the motor rotational speed is adjusted multiple times per second to obtain a precise wellhead velocity profile. This velocity profile is continuously recalculated and adjusted to maintain peak performance. This calculation is done in the cloud, and the simplified model is periodically updated to the edge device. For safety reasons, a fallback speed is implemented if the connection is lost for a certain amount of time.

4. Case study of various wells with improved well life and/or increased production

The system was tested on various wells of various flow rates, with and without gas issues, and of various depths and mean status quo SPM. Below we present several key results as to how the system has successfully been implemented.

Figure 4 illustrates the surface cards obtained on a 7,500’ TVD well without gas issues, running at close to 5 SPM, both without the system activated (blue) and with our system’s smart infra-stroke speed control enabled (orange).

Three key results are noted:

1. The max and minimum loads are significantly better optimized, with a peak-to-peak load reduced by 25%.
2. This is done at a constant 5 SPM average speed and a constant plunger stroke (not plotted here)
3. The optimized card in orange has an area 9% lower than the blue status quo card, so the electricity usage is also reduced by ~9% on a regen-enabled drive

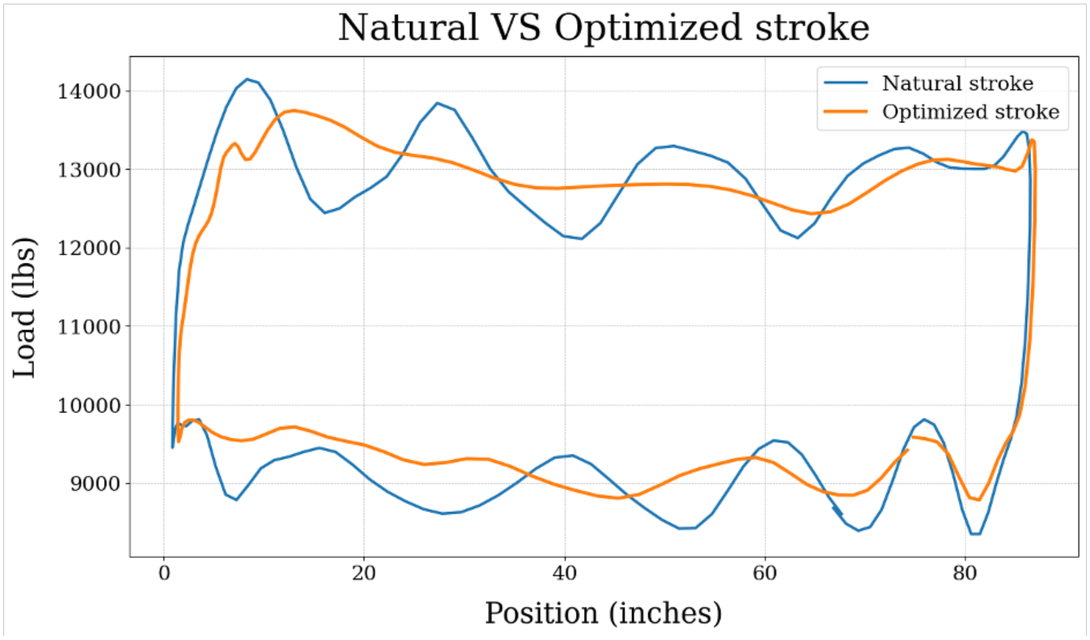

Figure 4 – Surface cards with constant mean SPM and reduced loads

Figure 5 illustrates the surface cards obtained on an 8,000’ TVD well without gas issues, initially running at 7.9 SPM using a VFD with no regen. This well production, in its current configuration, was rod-loading limited. The plunger was already at its maximum size, the pump was running as fast as reasonably possible to avoid a rod part. The system was activated and the stroke was optimized, enabling a new SPM of 9.0 with slightly minimised loads. The surface cards are plotted both without the system activated (blue) and with our system’s smart infra-stroke speed control enabled (orange).

Three key results are noted:

1. The well SPM was increased by 14%, and well production was increased by a similar amount.

2. The max and minimum loads are slightly optimised with a peak-to-peak load reduced by 2%.

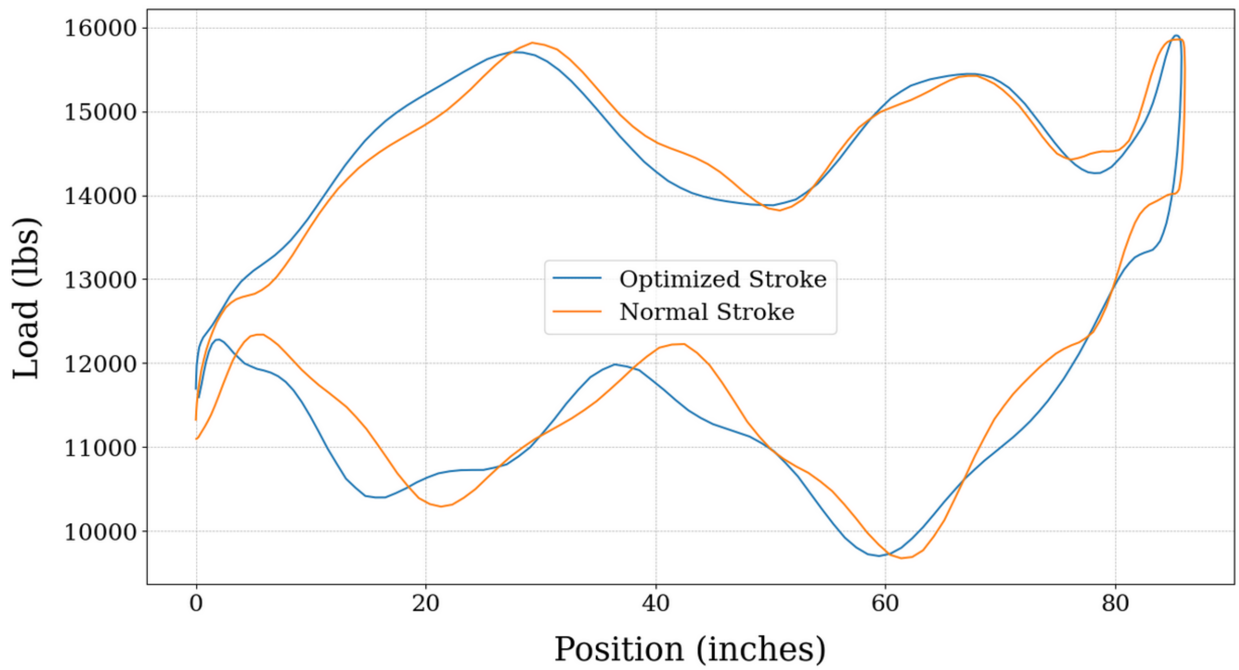

Figure 5 –Surface cards with increased SPM

5. Conclusion

This paper presents a new approach to enable advanced field control, specifically focusing on VFD-operated rod-pumped wells. By leveraging the latest telecommunication & cloud technologies, highly responsive & physics-driven AI modeling and, with our high-speed infrastructure & edge controller, we have demonstrated how very fine control of the well motion can be used to increase production, reduce wear & tear and cut electrical consumption. AI can be used to translate a user requirement in terms of production vs. wear & tear trade-offs into custom, well-by-well, velocity profiles which are continuously optimized and updated to match reservoir inflow characteristics. Additionally, this can be done with a very light hardware footprint, re-using sensors, drives and controllers already present on site.