Optimization of Plunger Lift Systems using Machine Learning

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1 Problem Statement

Liquid Loading in gas wells is a commonly occurring problem that can significantly decrease the performance of gas wells, in worst cases, it can stop the gas production completely. Artificial lift systems are deployed to lift the liquid from gas wells. The most commonly used artificial lift system is the plunger lift system because of its simplicity and robustness. The plunger lift system comes with a major drawback. The production of gas needs to be stopped for a certain amount of time (shut-in) to lift the liquid. Although, this can not be fully solved but the production rate of gas can be maximized by properly adjusting pressure values and other inputs involved in plunger lift systems. This proposal presents a set of rules based on the physics of plunger lift and the experience of field operators to calculate the values needed to maximize the production rate of gas. This will allow companies to increase their production rate and will also help in slowing down the aging process of gas wells.

2 Introduction

Plunger lift is a widely used method to unload gas wells. The plunger lift cycle consists of two phases. Shut-in and Flowing.

Shut-in $-$ The shut-in phase of plunger lift begins when the flow-line motor valve is closed. During this phase, the plunger falls down the tubing. It falls through gas and slug towards the bottom of tubing and rests on the bumper spring. The gas output from the well during the shut-in period is zero, as the flow-line valve is closed.

Flowing $-$ In this phase of the plunger cycle the flow-line valve is opened and the plunger moves upward under the force exerted by accumulated gas pressure in the casing. This phase is sometimes divided into two further steps. i.e. Unloading and After-flow. The unloading phase starts when the liquid-loaded plunger moves towards the surface of the well. After the unloading phase, the plunger arrives at the surface of the well and is captured there, During this phase the gas flow resumes normally. Figure 4 shows the plunger lift system and its necessary components.

The complete plunger lift cycle is shown in figure 2. The region $A - B$ represents the flowing phase of the cycle. During this region, the plunger moves upwards towards the surface of the well. At point 1, the liquid reaches the surface. At point 2, the plunger is reached at the surface where it is captured. From point 2 onwards, the after-flow phase begins where the gas is produced normally, towards the end of this phase the liquid again starts to accumulate in the tubing which results in a slight increase in casing pressure.

The region $B - C$ represents the shut-in phase of the cycle. During this phase, the plunger falls through the gas, at point 3 the plunger hits the liquid and continues to fall through the liquid. The plunger reaches the bottom of tubing at point 4 and the flow-line valve is opened again at point C where unloading begins and the plunger cycle repeats.

The goal is to avoid liquid loading as much as possible and improve the overall gas production, without damaging the equipment. The production rate of gas can be optimized by following proper rules based on the physics behind the plunger system. These rules are presented in section 4

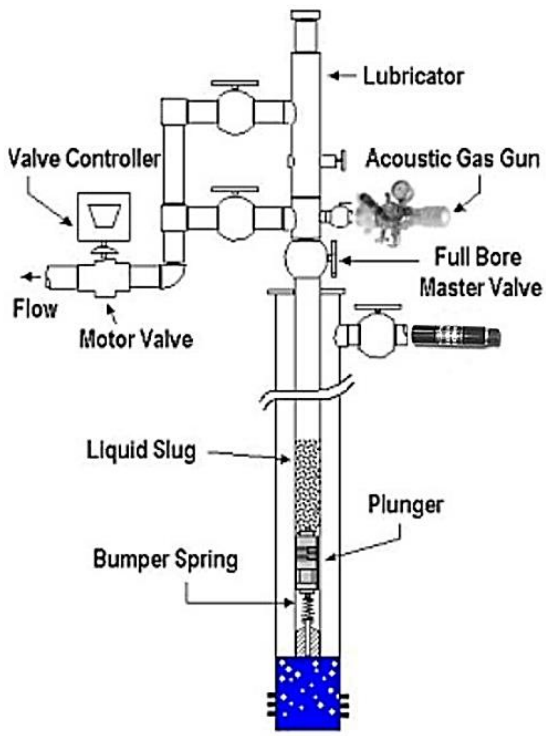

Figure 1: The plunger lift system.

3 Nomenclature

There are two tubes in the well known as casing and tubing. Throughout the document c subscript will be used for *casing* and t subscript will be used for *tubing*.

The following mathematical notations will be used throughout the document.

- **Gas Rate (G_r)**: represents the flow rate of produced gas. It is given in units of standard cubic feet (scf) per time unit (usually per day).

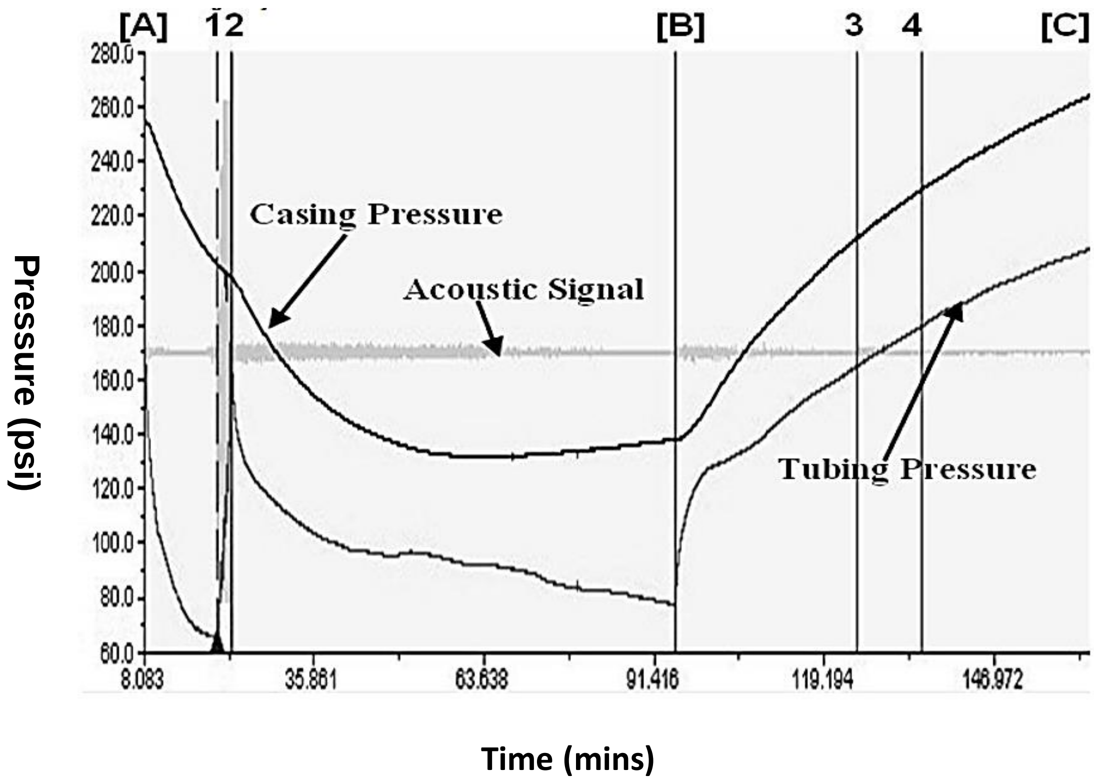

Figure 2: The casing pressure and tubing pressure of plunger lift system.

- **Gas-Liquid Ratio (GLR)**: The ratio of gas volume (scf) to liquid volume (bbl) being produced in the same amount of time. It is given in units of standard cubic feet per barrel (scf/bbl).
- **Liquid production rate (R_l)**: The rate of liquid produced or accumulated in the tubing and casing. It is measured in barrels (bbl) per time unit.
- **Volume of liquid (V_l)**: The volume of Liquid produced in tubing and casing. It is measured in barrels (bbl).
- **Depth of the well (D)**: represents the depth of the well or length of the tubing in the well. It is measured in feet.
- **Casing pressure (P_c)**: The pressure in the casing head of the gas well. The unit of pressure followed in gas wells is pound per square inch psi.
- **Tubing pressure (P_t)**: The pressure in the tubing head of the gas well. The unit of pressure is psi.
- **Line pressure (P_l)**: The output pressure of the gas production well. It is measured in psi.
- **Load factor (L_f)**: The ratio of liquid load in the well to the total energy provided by the accumulated gasses in the casing to lift the plunger and slug is called the load factor. Load factor is a unitless quantity.

- **Internal diameter (ID)**: The internal diameter of the tubing. It is represented by ID and measured in inches.
- **Specific gravity (SG)**: The specific gravity of the liquid accumulated in tubing and casing.
- **Height of liquid (h_l)**: The height of the gaseous liquid column in the tubing. It is measured in feet.
- **Minimum shut-in time (t_s)**: The minimum time required for the shut-in phase to complete.
- **Rise velocity (v_r)**: The rise velocity of the plunger needed to make sure that accumulated liquid is squashed out of the tubing.
- **Maximum unloading time (t_m)**: The amount of time taken by the plunger (loaded with liquid) to reach the surface of the well.
- **Cycle time (t_c)**: The amount of time taken by plunger to complete one cycle including shut-in and flowing.
- **Cycle time (t_a)**: The amount of time left for after-flow phase of plunger cycle.
- **Cycles (C_g)**: The number of plunger cycles in a day needed to fully remove the slug from the bottom of the tubing.
- **Required production rate of liquid ($STBPD$)**: $STBPD$ is the required production rate of liquid. This is used to determine the minimum number of plunger cycles to fully lift the liquid from bottom of the tubing.
- **Mass** : The mass of plunger given by m_p, mass of liquid given by m_l and mass of gas given by m_g accumulated in tubing. These three masses constitute the total load in tubing.

4 Baseline Rules for Optimal Performance

For optimal performance of the plunger lift systems, the following baseline rules are proposed based on the experience of operators and the physics behind the plunger lift systems **?**.

4.1 Gas Rate

The minimum gas rate needed for deployment of the plunger lift system is based on the liquid production rate at the bottom of tubing and the depth of the well through which liquid has to be moved. The simple relation between gas rate, liquid production rate, and the depth of well can be given as:

$$G_r > \frac{400}{R_l} \times \frac{D}{1000}, \tag{1}$$

The depth of well D is measured in feet. In other words, for a plunger lift system to be feasible in a well, there must be more than 400 scf of gas per barrel of liquid produced per 1000 feet of depth.

For example, a 5000 foot deep well will require gas-liquid ratio GLR to be more than $400 \times \frac{5000}{1000} = 2000$ scf/bbl for plunger lift to be feasible.

4.2 Load Factor

The load factor is used to determine if the plunger will come to the surface when the flow-line valve is opened to unload the well. The load factor is defined as follows:

$$L_f = \frac{P_c - P_t}{P_c - P_l}, \tag{2}$$

The numerator, $P_c - P_t$ i.e., the difference between casing pressure P_c and tubing pressure P_t at the end of the shut-in period (i.e., at point A in figure 2) can be thought of as liquid load as this pressure difference is mainly caused by the accumulated liquid. The denominator, $(P_c - P_l)$ i.e., the difference between casing pressure P_c at the end of the shut-in period (at point A in figure 2) and line pressure P_l just before the liquid arrives at the surface (at point 1 in figure 2), can be thought of as energy provided by the gas accumulated in the casing to lift the liquid load to the surface. The following upper bound can be used on the load factor to make sure liquid loaded plunger reaches the surface.

$$L_f < 0.5, \tag{3}$$

4.3 Casing Pressure

The minimum casing pressure (P_c) needed for the plunger lift system to be operable, i.e., to lift the plunger and liquid towards the surface is given by

$$P_c > P_l \times 1.5, \tag{4}$$

where P_l is the line pressure just before the liquid reaches the top of the well and P_c is the casing operating pressure at the end of the shut-in phase. The casing operating pressure P_c should be able to rise to a pressure of 1.5 times the line pressure P_l during a reasonable shut-in period.

The more precise value of the casing pressure needed to unload the gas well can be calculated using casing head volume (V_c), tubing head volume (V_t), the total mass of the load in tubing (i.e., the mass of plunger m_p, gas m_g and liquid m_l) and depth D of the well **?**.

During the shut-in period the compressed gas fills up casing-tubing annular with volume V_c, so the pressure built up in the casing provides total energy of $P_c V_c$. When the valve opens, this gas needs to at least fill all the space in casing and tubing (total volume = $V_c + V_t$) also providing the work needed to overcome friction and to lift the total load $(m_p + m_l + m_g)$ in tubing towards the surface of the well covering a total distance equal to the depth of the well D.

$$P_c V_c = P_t(V_c + V_t) + (m_p + m_L + m_g) \times \left(\frac{g}{g_c}\right) \times D + F, \tag{5}$$

g is gravitation acceleration and F is the work needed to overcome friction. $g_c = 32.2$ is a conversion factor needed to convert units of gravitational acceleration. The equation can be rearranged to solve for the exact value of casing pressure needed to lift the plunger and accumulated mass.

$$P_c = \frac{P_t(V_c + V_t) + (m_p + m_L + m_g) \times (\frac{g}{g_c}) \times D + F}{V_c}, \tag{6}$$

Since work needed to overcome friction is proportional to the amount of gas so we can express F in terms of m_g.

$$F \propto m_g \tag{7}$$

Putting the relation for F in equation 6.

$$P_c = \frac{P_t(V_c + V_t) + (m_p + m_L + (1 + C)m_g) \times (\frac{g}{g_c}) \times D}{V_c}, \tag{8}$$

where C is a constant relating F to m_g.

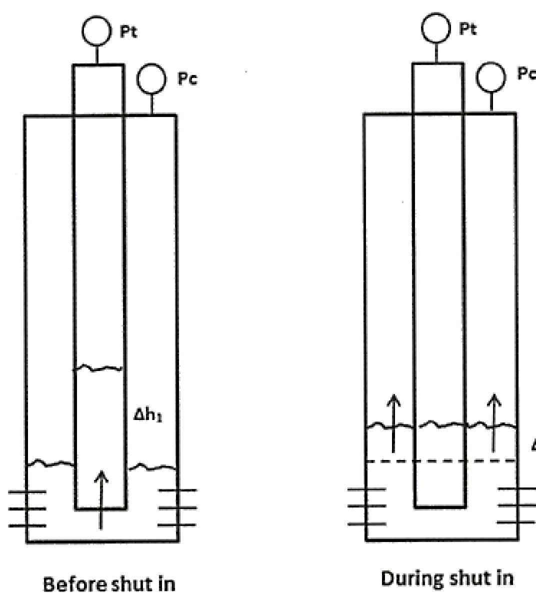

Figure 3: The difference in heights of liquid before and during shut-in.

The equation can be further simplified by substituting V_c and V_t with the well parameters. Δh_1 is the difference in height of liquid level in the casing and the tubing before shut-in starts, and Δh_2 is the increase in height of liquid level in the casing during the shut-in period as shown in figure 3. A_t and A_c are the cross-sectional areas of tubing and casing respectively. The following observations can be used to replace the volumes in equation 8:

$$V_t = A_t \times D, \tag{9}$$

$$V_c = A_c \times (D - \Delta h_2), \tag{10}$$

$$P_c = \frac{P_t[A_c(D - \Delta h_2) + A_t(D)] + [m_p + m_L + (1 + C)m_g] \times (\frac{g}{g_c}) \times D}{V_c}, \tag{11}$$

4.4 Amount of Liquid

The volume of liquid load in the tubing can be calculated by using the pressure difference in casing and tubing at the end of the shut-in period:

$$V_l = \frac{0.00224 \times (P_c - P_t) \times (ID)^2}{SG}, \tag{12}$$

ID is the internal diameter of the tubing and SG is the specific gravity of the liquid. The level (height) of the gaseous liquid column in the tubing can also be determined using the pressure difference in the casing and the tubing at the end of the shut-in period and the fraction of gas present in the gaseous liquid column FG. Usually, the value of FG is set to 0.8.

$$h_l = \frac{(P_c - P_t)}{0.433 \times (1 - FG) \times SG}, \tag{13}$$

4.5 Minimum Shut-in Time

The minimum shut-in time required for the plunger can be determined by noting the time for the plunger to fall through the gas in tubing, time to fall through the liquid, and any fudge factor to ensure the plunger arrives at the bottom of the tubing and enough casing pressure is built up before the shut-in period ends.

$$t_s = \frac{(D - h_l)}{v_{fg}} + \frac{h_l}{v_{fl}}, \tag{14}$$

where v_{fg} and v_{fl} are plunger velocities through the gas and the liquid in the tubing; these are determined to be $278.9 ft/min$ and $51.0 ft/min$ respectively during the shut-in period. These velocities are determined using the acoustic trace of the plunger as it falls through tubing collar recesses. The acoustic trace of the plunger shows spikes as it falls through the collars. Noting the distances of each collar and time of the spikes in acoustic trace, fall velocities of the plunger can be determined. The average of these velocities is used for the calculation of minimum shut-in time.

4.6 Rise Velocity of Plunger

The rise velocity v_r of the plunger, as the flow-line valve is opened, depends on the type of plunger used. The optimum rise velocity for most plungers is determined to be $1000 ft/min$. A higher velocity will result in damaged equipment and waste of energy of well, and if the rise velocity plunger is too slow, then the gas may slip through resulting in waste of gas and plunger may not rise to the surface of well.

For optimal operation of the plunger, the rule of thumb is to maintain a rising velocity between $500 - 1000 ft/min$. To calculate the maximum unloading time t_m of the plunger, we can use minimum from the range of optimal rise velocities i.e., $500 ft/min$, and divide the distance between bumper spring to surface with this velocity.

$$t_m = \frac{D}{500}, \tag{15}$$

4.7 Plunger Efficiency and Maximum After-flow Time

The plunger efficiency to unload the well depends on many factors such as the rise time, type of plunger, quality of the steal, well configuration, and age of the equipment. If the plunger is operated within good conditions and proper rise velocity ranges then a plunger efficiency of 100% can be achieved.

The number of cycles per day required to lift all the slug and liquid from the bottom of tubing to the surface of the well is dependent on plunger efficiency, liquid present in the tubing, and desired liquid production rate. The number of cycles (C_g) per day needed to fully remove the liquid can be determined as:

$$C_g = \frac{STBPD}{R_l \times Eff}, \tag{16}$$

$STBPD$ is the required production rate of Liquid. and Eff is the efficiency of a single plunger cycle. From the number of cycles per day we can determine the time taken to complete one plunger cycle in minutes

$$t_c = \frac{1}{C_g} \times 24 \times 60, \tag{17}$$

Knowing the time per cycle, the minimum shut-in time calculated as in equation 14, and maximum unloading time from equation 15, we can calculate the time for after-flow as:

$$t_a = t_c - t_s - t_m \tag{18}$$

Maximum number of cycles possible for the plunger in a day, can be calculated using the slowest arrival time (maximum unloading time t_m) and minimum shut-in time (t_s)

$$C_m = \frac{24 \times 60}{t_m + t_s} \tag{19}$$

Given the number of cycles, we can use equation 16 to calculate the maximum possible production rate of liquid. If the plunger is maintained for maximum number of cycles C_m in a day, then the resulting after-flow time will be almost zero.

5 What Machine Learning can do?

Although the baseline approach discussed in section 4 can result in a consistent gas production rate, avoiding the problems associated with liquid loading in gas wells but it is not enough to maximize the production rate or to diagnose a potential irregularity in the well.

Based on enough relevant data and labels supervised by field experts, machine learning based approaches can further optimize the plunger cycle resulting in increased gas production and output flow rates of gas.

After formulating a machine learning based problem, the first step to develop a machine learning system is to collect data and identify relevant information from the data. This allows the model to learn the patterns which contribute towards solving the specific problem. This relevant information extracted from data is called features. These features are used as input to the machine learning model. The model then learns a relationship between input features and the required output.

5.1 Features

The features that can be helpful in developing a machine learning model for plunger lift system are listed as follows:

- Casing pressure (P_c)
- Tubing pressure (P_t)
- Line pressure (P_l)
- Depth of the well (D)
- Liquid production rate (R_l)
- Tubing internal diameter (ID)
- Liquid specific gravity (SG)
- Acoustic trace of the plunger
- Fraction of gas in slug (FR)
- Plunger fall velocity through gas (v_{fg})
- Plunger fall velocity through gas (v_{fl})
- Plunger fall velocity through gas (v_r)
- Cross section area of casing (A_c)
- Cross section area of tubing (A_t)
- Mass of plunger, gas and liquid in tubing (m_p, m_g, m_l)

- Volume of casing (V_c)
- Volume of tubing (V_t)
- Plunger liquid removal efficiency (Eff)
- Desired liquid production rate ($STBPD$)

Note that some quantities like casing pressure, tubing pressure, line pressure, the acoustic trace of the plunger are dependent on the time of measurement, these quantities keep on changing with time. So, they need to be measured after every fixed interval of time and their values need to be recorded along with the time of measurement. This will result in a continuous data stream for such quantities. This is called time-series data.

5.2 Engineered Features

Apart from the measured quantities discussed in section 5.1, some other features are also important for machine learning. These features are derived or calculated from the measured quantities using a set of rules or equations based on theoretical knowledge behind the plunger-lift system. Therefore they are also called engineered or derived features as this information is not available in the system instead it is derived from the quantities measured in the system.

The important derived features that can be helpful are listed below:

- Minimum gas rate (G_r)
- Minimum casing pressure
- Load factor (L_f)
- Height of the liquid column in tubing (h_l)
- Volume of the liquid column (V_l)
- Time taken by the plunger to travel through the liquid in tubing (t_{fl})
- Time taken by the plunger to travel through the gas in tubing (t_{fg})
- Fudge factor (FF)
- total shut-in time (t_s)
- Plunger arrival time at the surface of well (t_m)
- Number of cycles per day to remove desired liquid (C_g)
- Time to complete one plunger cycle (t_c)
- Maximum after-flow time (t_a)
- Maximum number of cycles per day to remove liquid
- Maximum liquid that can be produced in a day

Some of these features directly affect the output flow rate of gas. The relationship of other features is not directly evident, machine learning can use different models to learn this relationship, which will play an important role in the final prediction of the required quantity.

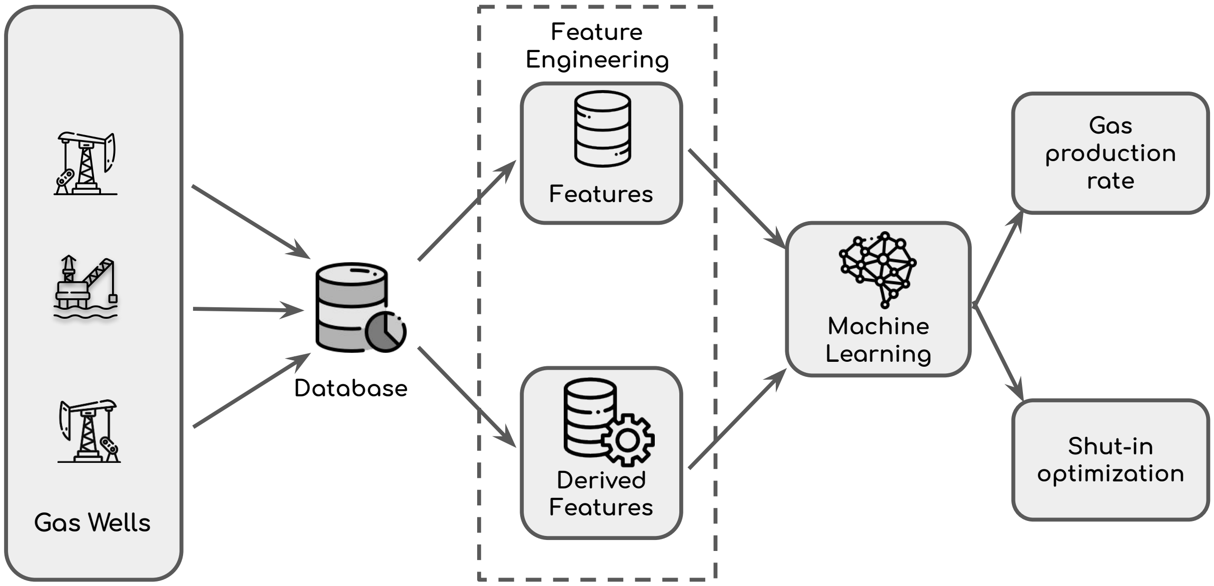

Figure 4: The high level diagram of proposed machine learning approach.

6 Queries

The following queries need to be answered before moving on to the machine learning phase of the project.

1 Can we control the rising or falling velocity of the plunger? i.e., can we accelerate or decelerate the movement of the plunger in the tubing? Does the casing pressure affect the plunger velocity? What other methods are available to change plunger velocities?

2 Is the plunger lift system passive or active? Can we control the pressure at the casing head?

3 For machine learning, the dataset consisting of thousands of samples from multiple wells containing all the features and derived features (if available) listed in 5.1 is needed. Is such a dataset available? How many wells does the dataset cover? How many features (from the feature list) are missing in the dataset. Please list the features that are not available? Can the features missing in the dataset measure or is it not feasible to measure these quantities?

4 The dataset needed should be labeled. There needs to be a clear mention of the best plunger cycles which yielded maximum production rate and worst plunger cycles that yielded minimum production rate. Gas production rate and shut-in should be mentioned corresponding to each plunger cycle. Shut-in time should be mentioned for each plunger cycle as large shut-in time results in reduced production and large rising velocity of the plunger which can damage the plunger. Similarly, if the shut-in time is small then the plunger cannot reach the well surface and fails to unload the liquid. For each plunger cycle, there should be mention of damage incurred to the plunger (if any). Are such labels available in the dataset? Is the dataset labeled by field experts?

5 Are the acoustic traces of the plunger as it falls through the tubing available for each plunger cycle? if not, can it be recorded?

6 Is the wellhead arrival sensor available? If not how do you know when the plunger has arrived at the surface to capture it?

7 Pressures need to be recorded periodically after fixed time intervals. Do you record pressure readings of the casing, tubing, and line pressure periodically? What is the value of the time interval after which periodic reading of pressures are taken?

7 Machine Learning based Approaches

Machine learning can be used to solve interesting problems based on the historical data of the plunger lift system for multiple gas wells.

Since the data provided for gas wells is usually in form of time series, i.e., different quantities are measured at different times (usually after regular intervals) So we can employ the dataset in two different ways i.e., to predict a missing quantity from given measurements at the same time instance or to predict a missing quantity or multiple quantities in a cycle based on the pattern learned from the history of these quantities from previous cycles.

Some important questions in plunger-lift systems in gas wells, that a machine learning model can solve, are as follows:

Estimating the maximum possible gas production rate − Given the tubing and casing parameters of the well and other related information, the goal is to estimate the maximum possible gas production rate that the well can produce **?**. This is a regression problem where the maximum possible gas production rate is to be determined.

Seemingly the maximum production rate of liquid inside the tubing is dependent on the size of tubing and the depth of the well (length of the well). We can train a regression model to estimate the liquid production rate using these two quantities as input features. A modified version of SVM (support vector machines) was trained for the given dataset which consists of tubing information (size and depth) of different wells and their associated maximum gas production rate. The model uses a classical support vector machine with RBF kernel and an additional least-square loss which is responsible to minimize the regression error.

Optimal shut-in time − During the shut-in phase of the plunger-lift cycle, the flow-line valve has to be closed which results in zero production during this phase of the plunger-lift. The objective is to minimize the shut-in time without compromising the liquid-unloading capability of the plunger. This can be done by a machine learning model which analyses the variations in casing and tubing pressures and other quantities over the past cycles to determine when shut-in needs to start and end for maximum production of gas.

To optimize the shut-in time we need to rely on the past plunger cycles and their time-series information of pressures, velocities, and acoustics. A machine learning algorithm can be used to measure the effective shut-in time, the start of the shut-in, and the end of shut-in required for the maximum flow rate without affecting liquid unloading. This can be done by using a neural network, which can learn such information based on the provided loss function.