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Simplified modeling of plunger-lift assisted production in gas wells

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ABSTRACT

Liquid loading has been an issue for mature gas wells due to declining reservoir energy. In older fields, one of the methods used to mitigate this problem is plunger lift. However, the optimum design of a plunger lift is nontrivial. This paper presents a simplified modeling approach for the design of plunger lift for wells in gas reservoirs with significant water production. The proposed model allows for an efficient design of plunger lift by incorporating energy balance in the wellbore.

The wellbore/reservoir model presupposes the presence of some liquid in the tubing and in the tubing/casing annulus, but most of the tubing and annular space is assumed to be filled with gas. Closure of the tubinghead valve initiates recuperation of reservoir energy, thereby allowing fluid influx to occur in the tubing and annulus. Eventually, accumulation of sufficient pressurized gas in the annulus lifts the plunger along with the liquid and gas on top of it.

The model accounts for the pressure-volume (*pV*) work done by the pressurized gas in the annulus, including the energy needed to lift the liquid and gas on top of the plunger, and friction during the plunger movement. Because the dimensions and trajectory of the wellbore have such profound impact on the operability of plunger lift, operators can use this model by just providing the known input parameters to determine the design variables, target casing pressure, and duration of the plunger cycle.

1. Introduction

With the depletion of gas reservoirs, the removal of produced water from the wellbores becomes less efficient. This inefficiency gives rise to water accumulation in the wellbore, a phenomenon known as liquid loading. The problem worsens in cases when significant water production occurs. The consequent increase in bottomhole flowing pressure significantly reduces gas production. A recent study of Riza et al. (2016) explored various mechanisms of liquid loading. One of the many methods used to combat this issue involves a plunger. Plunger lift is a method that uses the energy of the gas/liquid well more efficiently by allowing a free piston to travel up and down the tubing in a cycle.

Plunger lift is an attractive option for low productivity, high gas/liquid ratio (GLR) wells. Its major advantages include zero input energy, relatively small investment, reasonable operating costs, and efficient removal of paraffin and scale depositions. Perhaps the main disadvantages may stem from the requirement for continuous monitoring, the complexity of the lifting process itself, and a lack of understanding of optimizing and troubleshooting the lift method.

Several authors have addressed the modeling of plunger-lift installations. Some of these models have been accepted due to their simplicity; others require a more significant deal of time and data for designing and analyzing plunger-lift system performance. One of the earliest seminal works was that of Foss and Gaul (1965), in which they presented a force-balance analysis on plunger lift. They showed their design criterion in the form of charts that use values of parameters, including an average plunger velocity, based on their experience from operations at a particular field.

Attempts have been made to improve on the Foss and Gaul study by changing values of liquid load size, average plunger velocity, flow line pressure, effect of pipe diameter, among other variables by Hacksma (1972) and Abercrombie (1980).

Lea (1982) developed a model expressing plunger velocity concerning its acceleration, thus allowing plunger velocity to vary with depth. Many investigators attempted an improvement on Lea's model (Rosina, 1983; Avery and Evans, 1988; Marcano and Chacin, 1994; Baruzzi and Alhanati, 1995; Maggard et al., 2000; to name a few), generally by accounting for liquid fallback through field data or laboratory work. Gasbarri and Wiggins (2001) further advanced Lea's work by considering the plunger downstroke.

Recent advances in plunger lift system include the development of ‘smart plungers’ that can record pressure and temperature data. This

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real-time measurement, in turn, helps to optimize the plunger lift performance. Chava et al. (2008, 2010) introduced significant improvement through the use of 'smart plunger' and developed a model for them. Tang and Liang (2008) also improved on dynamic modeling of the plunger-lift system by combining it with field test data and not limiting to constant tubing pressure. Parsa et al. (2013) worked further in connecting the plunger lift system to the performance of tight, unconventional gas wells. They proposed a reservoir-performance based algorithm to optimize the gas production and shut-in periods of plunger lift operation. More recently, simpler models for optimizing plunger lift performance in field operations have gained traction. For instance, Luo and Kelkar (2014) provided such a model that enables determining target casing pressure, leading to sustained production. Their model accounts for casing and tubing pressures before and after a plunger cycle, and the volumes of the tubing and tubing/casing annulus. Nurkas (2016) provided a simple procedure for plunger lift candidate well selection process. Their procedure was based on the estimation of liquid loading and rules of thumb regarding required gas production rate. Kamari et al. (2017) introduced another model to check on maximum possible liquid production rates by use of plunger lift. Their model is loosely a function of tubing size and well depth. However their model relied more on predicting what the plunger system could lift rather what the reservoir could still deliver.

This study offers a simple plunger lift model based on energy balance by developing an expression for the minimum casing pressure needed for sustained production. To achieve this goal, the wellbore model is connected to a numerical reservoir model. This wellbore/reservoir connectivity allows determining the shut-in time needed to achieve the desired casing pressure for prolonging the production cycle. Equally important, besides understanding the current production and shut-in cycles in a given well, this forward model allows probing the suitability of a given well for plunger lift application.

2. Model development

When a gas well begins to load up, its production starts to decline and ultimately the well dies. One way to avoid a well being completely 'killed' with liquid loading is to shut the well in (stopping production), and let the pressure at the well bottom build up. Then open the well at an appropriate time (when the bottomhole pressure has built up "enough") so that there is enough energy for the well to produce again for quite some time. This process of shutting in the well to build up the pressure and then flowing the well can be aided by a plunger. Plunger lift uses the built-up energy of a temporarily shut-in well to move much of the accumulated liquid up from the well bottom to the surface.

To efficiently run this cyclic process of shutting in and restarting production, the well should not be shut-in for too long; yet, must be shut-in for long enough for the pressure to build up to a certain level that allows continuous production for quite some time. The objective of this study is to develop a model that enables estimation of pressure buildup in the well after shut-in, which allows subsequent sustained production.

Assumptions.

1. Efficient production requires a gas well to operate in the annular two-phase flow regime. In annular two-phase flow, especially at the low pressures of brownfields, the liquid-volume fraction in the wellbore is likely to be less than 5%. For estimating wellbore gas mass, we assume that most of the tubing and annular space are filled with gas.
2. The production ceases upon closing the tubinghead valve, thereby allowing afterflow to occur from the reservoir to accumulate in the tubing/casing annulus.
3. After pressure buildup and when the plunger is released, the pressurized annular gas lifts the plunger along with the liquid and the gas on top of it.
4. The pressure-volume (pV) work done by the pressurized annular gas must also account for energy needed to lift the liquid and gas on top of the plunger, and the friction during plunger movement.
5. After the plunger reaches the top, the pressure at the tubinghead will be the known line pressure that needs to be maintained for quite some time (for sustainable production) before the next cycle begins. Therefore, for calculating pV at the end of upward plunger movement, the line pressure will be used along with the well volume.
6. The pressures at the top and bottom of the tubing and casing are related by the exponential expression for the standing-gas column, $p_{bh} = p_{wh} e^{(gMD)/(RZTg_c)}$ where M is the gas molecular weight and D is the vertical distance between wellhead and bottomhole.

The plunger should be released from the bottom seat only after the annular pressure has increased high enough so that the tubinghead pressure reaches above the line pressure upon expansion of fluids, and the arrival of the plunger and liquid to the wellhead. We analyze the process by examining the energy available just before the plunger starts ascending and compare that to the final stage of the process when the plunger has moved all the way up. We use the pressures at the tubinghead (p_t) and casinghead (p_c) to represent the pressure in the entire tubing and casing, respectively.

Energy available in the annular gas just before the plunger is released is the pressure-volume (pV) work that equals $p_c V_c$ (ft-lbf), where V_c is the total volume of the gas in the tubing/casing annulus. This energy must be at least equal to the final pV work that is given by $(pV)_{\text{total}} = (p_t V_c + p_t V_t)$. Also, energy must be spent to move the plunger, and water and gas on top of it to the wellhead (potential energy), and overcoming friction in doing so. The gain in potential energy of the plunger-fluid system is proportional to the total mass of plunger (m_p) plus fluid on top of the plunger ($m_L + m_g$). Therefore, energy balance is written as

$$p_c V_c = p_t (V_c + V_t) + (m_p + m_L + m_g)\left(\frac{g}{g_c}\right) D + F \tag{1}$$

The frictional loss of energy depends on the mass of the fluid plunger system, in addition to the well depth. For simplicity we assume that the frictional loss F is small compared to the other terms and is included in the gas static-head term as a small fraction C. Therefore, Eq. (1) can be rewritten as

$$p_c V_c = p_t (V_c + V_t) + (m_p + m_L + (1 + C) m_g)\left(\frac{g}{g_c}\right) D \tag{2}$$

Before the tubinghead valve is opened to allow the plunger to move up, the casing pressure must rise to a value given by the following expression:

$$p_c = \frac{p_t (V_c + V_t) + (m_p + m_L + (1 + C) m_g)\left(\frac{g}{g_c}\right) D}{V_c} \tag{3}$$

3. Model validation

We used the data offered by Luo and Kelkar (2014) to validate the proposed modeling approach. They provided data from four wells, where two of them sustained continuous production after shut-in, but the other two did not.

Fig. 1 presents daily production data along with tubinghead pressures for Well 1 in the Luo-Kelkar study. The decline in gas flow rate, with a consequent rise in tubing pressure, signifies liquid loading. The schedule followed in the field data for the first plunger cycle is given below; subscript 1 represents conditions just before shut-in, and subscript 2 represents conditions when the well is opened up again, and the plunger begins its ascent: