Abstract

The premise that high annular velocities on rod pumped gas wells can cause liquid holdup in the casing is presented. A case is then made (using conventional vertical separator sizing equations) that the annular cross-sectional area is inadequate to allow gas-liquid separation to occur, preventing fluid from falling below the turbulent perforations to the pump intake. The concept of “Batch Pumping” is presented to industry as a simple, cost effective method to solve this separation problem for any well with this liquid holdup problem.

Introduction

What is “Batch Pumping, and what is “Downhole Liquid Holdup”? The term “Batch Pumping” is derived from the chemical industry, which has processes that usually fall into one of two categories: batch or continuous. In a continuous process, the ingredients are mixed on the fly (continuously), and the products of the reaction come out continuously. In a batch process, the ingredients are mixed in a vessel where they react. They are then unloaded from the reactor, and the process is repeated.

Relating this to a common oilfield example, examine the operation of a level controller on a conventional separator. Some designs are snap acting, waiting for the vessel to fill to a certain level, upon which the vessel is then drained to a certain lower level. This is a batch process. The level controller could also be of a throttling design, which maintains a constant level in the separator by varying the output of the controller to partially open the dump valve. This would be a continuous process.

“Downhole Liquid Holdup” is observed when the tubing-casing annular area is too small for effective separation of gas and liquid, yet so large that the critical velocities needed to lift fluid per Turner et al cannot be achieved. The result is that liquid accumulates in the annulus, since it can neither flow to surface, or fall below the turbulent perforation area. The net result of this liquid accumulation is increased backpressure on the formation, the opposite of our intention when artificial lift was chosen for the well.

Batch Pumping for Rod Pumped Gas Wells

For a rod pumped well, we normally have a continuous process, where gas and liquids enter the wellbore via the perforations. Fluids are pumped out using a pump. Where pumping units are equipped with Variable Frequency Drives, the speed of the pumping unit can be controlled with a Pumpoff controller to exactly
match the fluid entry from the well bore, a continuous process. Where VFD’s are not utilized, we turn off the pumping unit intermittently to prevent gas from locking the pump, and to prevent associated equipment damage. In this situation, the liquid is pumped in a batch process.

Regardless of whether the pumping unit removes fluids continuously or in batches, the flow of gas up the casing annulus is normally continuous, never interrupted except for compressor downtime, etc. This paper proposes that gas flow be changed from a continuous process to a batch process in order to solve downhole separation problems.

**Identifying and Solving Downhole Liquid Holdup**

Gas wells with casing or liner sizes typically smaller than 5-1/2" O.D. have an annular area that is often too small for effective downhole separation of gas and liquids. Industry rarely makes surface separators from anything less than 8-5/8" diameter for a reason. For us to expect 4-1/2" or 5-1/2' casing to function as a separator just because it is very long is not logical. Separator sizing equations are based on gas velocity:

\[ v = K \left( \frac{\rho_L - \rho_g}{\rho_g} \right)^{1/2} \]

\[ A = \frac{Q}{v} \]

where:

- \( v \) = Superficial gas velocity
- \( \rho_L \) = Density of liquid
- \( \rho_g \) = Density of gas
- \( K \) = Emperical factor
- \( A \) = Cross sectional area
- \( Q \) = Gas flow rate

Since velocity is inversely proportional to the cross sectional area, and area is a function of diameter squared, an 8-5/8" diameter separator has roughly four times the separation capacity of a 4-1/2" diameter “separator”. Place a piece of tubing inside the separator, and the capacity is further reduced.

The following graphs depict calculated values for both the annular separation capacity of various tubular combinations as well as the critical liquid loading flowrates based on the Coleman modified Turner values. The separator calculations are based on the above equation. The Coleman modified Turner calculations were made at the same temperature and pressures but with an equivalent tubing string diameter that would yield the same cross-sectional area as the tubing – casing annulus.
It can be seen from these graphs that the Coleman values average nine (9) times higher than separation values. Also, the separation capacities are quite low. In reality though, when downhole liquid holdup becomes significant, the flowing bottom hole pressure will have a resulting increase, dropping the velocity to the point that some separation will occur, and equilibrium will be reached.

Compounding the separation process in the vicinity of the perforations is the turbulence created as gas and liquids enter the annulus. Depending on the well productivity along with the size, quantity, and number of the perforations, there can be situations where the turbulence can further impede the separation process by “stirring” everything.

**Methods to Identify Downhole Liquid Holdup**

There are several indicators that can be used to identify wells suffering from downhole liquid holdup. The below list is presented as the author’s proposal based on personal experience:

- Wells pumping at 15% or less (with pumpoff controller)
- Wells that initially responded well to rod pumping, but dropped off over a period of several days (as liquid accumulated)
- Wells that are erratic producers
- Wells producing at flowrates greater than 40% of Coleman

It is extremely simple to perform a field test to confirm the existence of downhole liquid holdup. The procedure is:

- Time length of normal pumping cycle
- Prior to start of pumping cycle, manually shut-in casing for 10 minutes, and time length of this pumping cycle
- Open casing valve when pumpoff completed
If the length of the pumping cycle was appreciably longer when the casing valve was closed, then you have downhole liquid holdup. This test was performed on a Pettit producer in Panola County on a well that had been pumping only 3 minutes of every 30 minutes. The resulting pump cycle lasted for more than 45 minutes, at which time the test was called.

**What Happens When the Casing is Shut-in?**

When the casing valve is shut, the gas flow in the annular area falls to essentially zero. When this happens, gravity takes over, as the gas flow rate is no longer attempting to drag liquid droplets up with the gas stream. Now, the annulus can function very effectively as a separator.

**How to Resolve Liquid Holdup**

The above testing process can be easily automated. A pneumatic or electric powered valve of sufficient diameter should be installed on the casing outlet. A time delay relay can be installed to delay (the POC called for) pumping unit startup. Once the POC calls for the pumping unit to stop, then the valve will reopen. The opening of this valve may need to be regulated to prevent surface separation or gas metering issues, as pressure will have built up behind it.

Just as in plunger lift, the goal of maximizing gas production will be met by minimizing the periods of time that the well is shut-in. Therefore, consideration to increasing pumping capacity should be given, as the well can be returned to production sooner if the fluid is removed faster.

It would be helpful to industry if pumpoff controller manufacturers would modify their POC’s to incorporate valve control to their product, where additional relays did not have to be added by the operator.

**Optimizing Shut-in Time Prior to Starting Pumping Unit**

Field experiences in East Texas on 6000 foot TVD wells suggest that shut-in times of 6 to 8 minutes prior to the start of pumping are optimum. This is enough time for fluid to fall to the pump intake (so that there is something there to pump), but keep in mind that fluid continues to drain to the bottom of the well during the pumping cycle as well.

**Example Production Curves for the First Candidates**

Production curves for three of the first wells in Panola County, Texas follow:
Since 2000 when these first projects were completed, many additional wells have been converted to batch pumping operation. Most of them had 4-1/2” casing, but many were wells that had liners in the perforated interval.

It should be pointed out that this method is best applied to wells with very low reservoir pressure, where slight increases in flowing bottom hole pressure have demonstrated the ability to adversely impact production.

**Opportunities to Improve the Batch Pumping Concept**

To maximize the duration of the flow period (and hence maximize production), opening the casing valve as early as possible is desirable. If the POC could have the ability to anticipate when pumpoff will occur (based on the previous cycles), and open the valve beforehand, this would help maximize production. It makes sense that adequate rathole beneath the perforations should be available to hold fallen fluid so that it can be pumped out. The valve can be opened whenever the majority of fluid has fallen past the perforations into the below perforation holding volume. A trial and error system much like plunger cycle optimization would likely be required.
Conclusion and Recommendations

1. The process of “Batch Pumping” provides a method to transport fluid held by dynamic forces above the perforations in the tubing-casing annulus down to the pump below the perforations.

2. Vertical wells with low reservoir pressure yet high producing velocities are likely to benefit most from this process.

3. A simple field test can verify whether this process will be effective.