

buildup of bottom-hole and casing pressure to lift the liquid slug or if the plunger is held in the wellhead during a production period. Typically, plungers are used on gas wells that have a sufficiently high gas-liquid ratio (GLR) to operate solely with a plunger on formation gas. However, plunger-lift installations can be designed to use makeup injected into the annulus gas when the available produced gas is insufficient. A minimum GLR can be calculated for different conditions but is usually around 3,000–5,000 scf/bbl. Typically with high-GLR wells, the slug size is small and the operating pressures are relatively close to line pressure.

The following example of the plunger cycle is given to further explain the operation and characteristics of a plunger installation. The example is from an actual well. The three cycles shown may be more complex than found in the typical installation, but they serve to bring out several points that can be helpful in examining the production and pressure characteristics of other plunger lift cycles. Refer to the numbered stations on Figure 6.15 to follow the cycle description.

Station 1. The well was initially shut in to build up pressure sufficient to surface the plunger. The tubing is open to the flow line, and the plunger begins to surface with the reduction in tubing pressure. "Top gas" above the plunger and the liquid load is produced.

Station 1'. The liquid slug has arrived at the sur-

face. The liquid slug passes through surface line and fittings and results in a pressure spike on the tubing pressure gauge. Casing pressure decreases as casing gas feeds into the tubing under the plunger.

In this example, the plunger is operated with a time-cycle controller and the well is allowed to produce after plunger arrival with the plunger held at the surface. Tubing pressure continues to decrease as the gas flow rate decreases following plunger arrival. Production of gas after arrival is common when the GLR exceeds the minimum required.

The casing pressure reaches a minimum as gas feeds into the tubing but then begins to increase because of liquid holdup in the tubing, which results from an insufficient gas rate to clear the tubing. The casing pressure must always be higher than the tubing pressure in the flow period in order to support the flowing tubing multiphase pressure gradient.

Station 2. Gas rate has diminished to 200 Mcfd (unsatisfactory low differential reading on the orifice meter for this example) and the well is shut in for a pressure buildup.

Note the sudden increase in tubing pressure as gas and liquid phases separate and the flowing pressure gradient (primarily caused by the liquid holdup in the tubing) is lost. The ensuing gradual tubing-pressure buildup is due to new gas production entering the wellbore. The uniform slope of this buildup indicates that

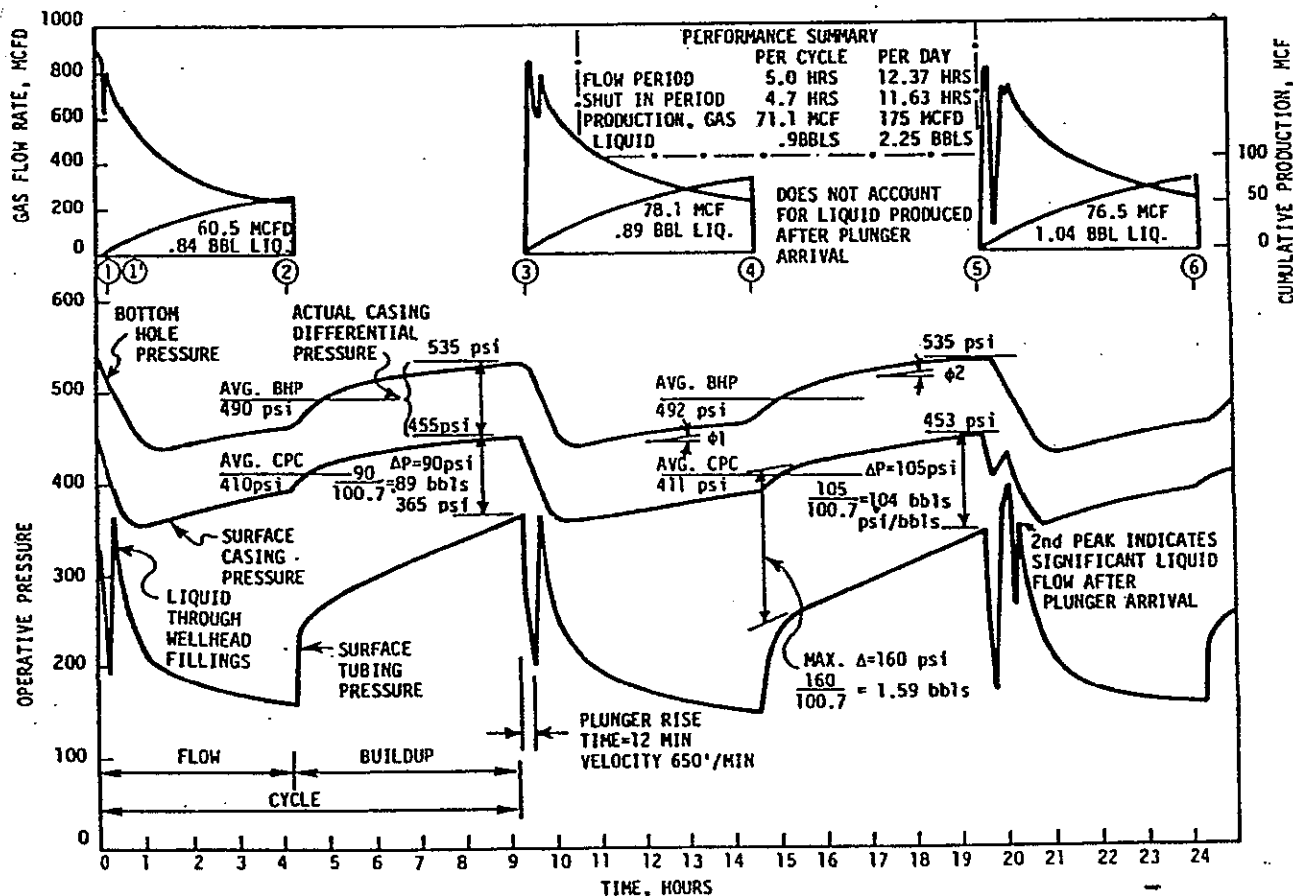


Figure 6.15 Example of Plunger Cycle—Lee Gould Jr. Unit Well No. 1, Wattenberg, Colorado

the well is continuing to build up fairly uniformly throughout the buildup period.

Station 3. Tubing is open to flow. The previous cycle is repeated. Note the indication of plunger travel time (12 min) as shown by the drop in tubing pressure to a minimum value and the sharp peak achieved as the liquid slug reaches the surface line and wellhead fittings, which are in effect "choking" the flow.

The liquid slug size above the plunger may be estimated by dividing the 90-psi differential pressure between the casing and tubing by the equivalent column pressure of 1 bbl of produced fluid in the tubing (for 2½-in. tubing, 1 bbl = 258.6 linear ft/bbl \times 0.433 psi/ft \times 0.8 SpGr = 100.7 psi/bbl). This calculation indicates 0.89 bbl of liquid in the tubing.

Station 4. Flow has diminished to a 200-Mcfd reading on the orifice meter, and the well is shut in for the buildup cycle.

Note that at this time the pressure differential between tubing and casing is 160 psi, which corresponds to a static fluid column of 1.59 bbl of liquid in the tubing (neglecting flowing friction). Based on the buildup in casing pressure during the shutin period, it is estimated that the volumes of gas entering the casing and tubing during the shutin period were 1.75 and 1.13 Mscf, respectively. The associated liquid volume based on a liquid-gas ratio of 13 bbl/MMcf would be 0.024 and 0.015 bbl, respectively, for the casing annulus and tubing. Thus, during the shutin portion of the cycle, 2.87 Mscf of gas and 0.039 bbl of liquid entered the wellbore. This is compared to an average 78 Mscf of gas and 0.9 bbl of liquid produced during the total cycle. The production flow into the wellbore during the shutin period appears to be causing a faster buildup in the tubing pressure compared to the casing pressure. Actually, the more rapid rise in tubing pressure may be due to some liquid draining from the tubing into the annulus. At the end of the buildup period, the casing-tubing differential is 105 psi, indicating 1.04 bbl of liquid remain in the tubing over what is in the casing above the bottom of the tubing. If there is liquid in the annulus above the tubing inlet, it will feed into the tubing under the plunger on the next production cycle. The most reliable way of knowing how much liquid must be produced during the cycle is to measure the liquid on several cycles. Liquid draining from the tubing can be controlled with a tubing standing valve, and/or the amount of liquid in the wellbore can be reduced by decreasing the flow period.

Note that the slope of the buildup lines, both BHP and the surface casing pressure during the shutin period, do not change near the end of the buildup cycle. This constant slope indicates that the gas influx rate into the affected well drainage area is fairly uniform throughout the buildup period, and the long buildup time does not significantly affect the well's production in this tight (low-permeability) reservoir. A slope that leveled off during the shutin period indicates that the buildup cycle would inhibit maximum production expected. The optimum setting for buildup time is the shortest time that provides sufficient pressure to surface the plunger plus liquid slug. Following calculations will quantify the needed pressure.

Station 5. Buildup pressure is complete and the tubing is open to the flow line. Note that there is a second

peak on the tubing-pressure recording following the large peak caused by the liquid slug above the plunger passing through restrictions in the surface. The second peak is presumed to indicate some liquid production after plunger arrival (i.e., liquid from the casing annulus or below the tubing feeding into the tubing below the plunger).

Station 6. The flow period is over and the tubing is shut in for the next buildup cycle.

Although the description given above was for a time-cycle controlled plunger operating in a well without a packer, other types of plunger installations have similar characteristics. Other cycles will vary slightly, depending upon the type of cycle controller used and whether the well is equipped with a downhole packer. Where a downhole packer is installed, the formation must supply all of the operating gas during the time the tubing is open for flow. A downhole packer for wells on plunger lift will probably prevent successful operations unless an outside high-pressure gas source is used for the lift gas.

Special wells may require or may show improved operations by a continuous low production of gas from the tubing at all times. This is accomplished by a bypass small-choke arrangement around the time-cycle controller. This permits more liquid entry above the plunger for the next cycle.

6.23 SELECTION OF WELLS FOR APPLICATION OF PLUNGER LIFT

Plunger lift is one preferred method for removing liquids from low-producing-rate gas wells. When the producing rate is in the liquid holdup region of a tubing performance curve, the well begins to produce large liquid slugs (heading) that may require intermitting to clear liquid accumulations from the tubing. These conditions indicate that the well is a good candidate for a plunger installation.

Plunger lift is suited for producing liquid from wells over a wide range of conditions and is capable of producing many wells to satisfactory reservoir depletion pressures. This is particularly true for wells with high GLR's. Higher GLR's allow production with smaller liquid slugs and, hence, lower operating pressures. Tubing size also affects the operating pressure for a given slug size.

The minimum GLR to operate plunger lift is the actual minimum amount of gas in the tubing volume at maximum cycle pressure (in scf) divided by the captured slug (bbl) at average wellbore temperature at which the plunger cycle will still function. The minimum GLR for a plunger lift well can be calculated using gas pressure/volume relationships. As the producing GLR approaches the minimum GLR, the slug size increases for a given amount of production. Since an increase in slug size requires a corresponding increase in operating pressure, it is a matter of economics and field experience to determine if low-GLR wells should or can be produced by some type of method other than plunger lift. If the formation has low permeability and the casing pressure buildup is steady throughout the shutin period, as illustrated in the example, plunger lift is probably the best method for removing small quantities of liquid production.