Authors Suggest Technology To Control Liquid Loading

As production begins to decline in mature gas wells, the presence of certain liquids in the wellbore can be a real headache for operators. Liquid loading occurs when liquids being produced increase the flowing bottom-hole pressure, and can restrict gas production dramatically. Many of these liquids come in the form of accumulated condensation from other portions of the well, or sometimes are produced directly in the wellbore.

In a paper titled “Solving Gas-Well Liquid Loading Problems (SPE-72092),” James F. Lea from Texas Tech University and Henry V. Nickens with British Petroleum discuss effective treatments for these situations. They suggest there are multiple actions one can take to reduce liquid loading in gas wells, including flowing the well at a higher velocity by using smaller tubing, or by creating a lower wellhead pressure.

They also suggest pumping the liquids out of the well or even foaming the liquids to allow the gas to lift the liquid from the well. Additionally, they suggest pumping water into an underlying disposal zone, or preventing liquid production altogether by shutting off a water zone or using insulation to reduce the formation of condensation.

Before selecting which option best suits his wells, an operator first must identify whether liquid loading is the culprit. Lea and Nickens admit that identifying whether liquid loading is a problem can be difficult since many liquid-loaded wells continue to produce for a very long time. The authors advise that if an operator begins to see sharp dips in a well’s decline curve or begins to see liquid slugs at the surface, liquid loading may be an issue. They also say that a difference between the tubing and casing flowing pressures, or sharp changes on a pressure survey, indicate the operator should look into possible solutions to continue a slow and regular production decline.

An operator faced with liquid loading has many options for addressing the situation. However, one in particular has been popular in the United States: plunger lift. This economic solution has been accepted widely by operators working in areas with mature wells and largely depleted reservoirs. In his paper, “Plunger Lift Applications: Challenges and Economics (SPE-164559),” Mohamed Hassouna from Lufkin Industries describes the process as a very reliable and viable system that has matured in recent years.

Hassouna explains that the process uses a free-flowing plunger within the tubing string to bring accumulated liquids from the wellbore. This system allows the plunger to sit at the bottom of the well on a bumper spring, and takes advantage of the well’s own energy by letting pressure build inside the well while shut in. The plunger acts as a seal between the liquid above it and the gas and tubing below. Once the well is opened, the pressure from the well pushes the plunger to the wellhead and the liquid from the wellbore.

With many operators wanting to optimize production, each operator needs to consider the pros and cons of various solutions. Hassouna notes many wells require artificial lift to maintain production at a desired rate. However, when that rate begins to decline, it becomes difficult and cost prohibitive to maintain certain wells and they ultimately are abandoned. He says plunger lift is a popular method because it increases the economic life of the well and can help take a well to near depletion. Additionally, this method requires a relatively low capital investment and operational costs, making it the preferred solution for many liquid-loaded gas wells.

As these systems were embraced by operators across the country, there became a need for even more efficiencies and optimization of units among folks with large numbers of plunger lift systems. In a paper titled “Well-Performance Diagnostics using Smart Plunger Technology (SPE-120596),” Travis P. Gray from Texas Tech describes the problem with having to “tune” individual systems to meet the needs of a changing reservoir.

As more and more units begin to be put online, it becomes necessary for operators to find an economical solution for making adjustments in the field. Gray highlights how technology has helped to address the problem by using personal computers combined with programmable logic controllers. Through remote terminal units, it became possible to open and close valves remotely for multiple wells from the home office. Additionally, by using a smart plunger system, information can be sent to engineers, allowing them to make additional adjustments and “tune” the systems remotely.

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