The Use of Coiled Tubing as a Velocity String

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Abstract

Liquid loading is a problem in many gas wells especially older and depleted type reservoirs. If steps are not taken to minimize this effect, it will severely limit the production or even "kill" the well. This is the result of insufficient transport energy in the gas phase to carry the liquid that will accumulate around the well bore. This accumulation exerts a backpressure that restricts reservoir inflow performance.

Reducing the flow area of a gas well's existing production string increases flow velocity and improves the ability to unload liquids. The most economical method is to install coiled tubing inside the existing tubing string that can be done without killing the well.

Introduction

The presence of liquids (formation water and/or condensate) in gas wells can reduce production. Their presence in flow stream has significant impact on the flowing characteristics and they must be carried to the surface by the gas phase to prevent liquid accumulation within the wellbore. The reason for such accumulation is the lack of transport energy and the result is an increase of bottomhole flowing pressure and decrease in the well's production.

Liquid loading is indicated by sharp drops in a decline curve, onset of liquid slugs at the surface of well, increasing difference between the tubing and casing flowing pressures with time and sharp changes in gradient on a flowing-pressure survey. (Lea, J.F., Nickens, H.V, 2004.) A common method for identifying liquid loading effects is through the examination of a wells production history. And the most accurate method of detecting liquid loading is obtaining periodical flowing and shut-in bottom hole pressure gradient profiles.

Multiphase flow (Wesson, H.R., Jr, 1993.)

With multiphase flow in the well there are several flow patterns of interest in vertical or near vertical upward flow. There is four flow patterns of primary interest: bubble, slug or plug, transition and annular flow. These flow patterns are function of the liquid rate, gas rate, liquid density, gas density and interfacial tension. Bubble flow pattern occurs at relatively low gas rates. The gaseous phase is present as bubbles dispersed in a continuous liquid phase. They move at a velocity greater than the average velocity of the liquid phase. As the gas rate is increased, the bubbles start forming larger bubbles. Such large bubbles have shaped nose and are called Taylor Bubbles. They are surrounded circumferentially and separated by the liquid phase that can contain separated small gas bubbles that are flowing upwards as a plug flow. Further increase of the gas rate results in highly agitated mixture of the liquid and gaseous phase – the transition flow. With larger gas rate the annular or annular mist flow develops. This pattern is characterized by the presence of a fast-moving core of the gaseous phase carrying entrained droplets of the liquid phase and as an upwards-flowing film on the conduit.

The most important characteristic present in all four patterns is a relative velocity difference between the two phases that determines the holdup or accumulation of one phase compared with the other. The annular mist flow pattern results in minimal accumulation of liquid within the well bore. The liquid phase is removed from the well bore by the combination of interfacial shear, from drag on the waves of gas/liquid interface and drag on the entrained droplets. That means that gas velocity in the core must be sufficient to carry the entrained liquid droplets upward and is obtained determining a force balance between the gravity and drag forces on a droplet:

$$\frac{1}{2} \cdot C_d \cdot \left(\frac{\pi \cdot d_k^2}{4} \right) \cdot \rho_g \cdot v_g^2 = \left(\frac{\pi \cdot d^3}{6} \right) \cdot g \cdot \left(\rho_l - \rho_g \right) \tag{1}$$

Where:
C_d – drag coefficient
d_k – drop diameter, m
ρ_g – gas density, $kg \cdot m^{-3}$
ρ_l – liquid density, $kg \cdot m^{-3}$
V_g – gas velocity, $m \cdot s^{-1}$
g – acceleration due to gravity, $m \cdot s^{-2}$

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When rearranged yields to:

$$v_g = \left(\frac{2}{(3)^{1/2}} \right) \cdot \left(\frac{\left(g \cdot (\rho_l - \rho_g) \cdot d_k\right)}{\left(\rho_{g \cdot C_d}\right)} \right)^{1/2} \qquad (2)$$

Velocity string design

Determination of the effects that a velocity string will have on a well is obtained through the nodal analysis simulation (Brown, K.E.). The analysis includes the system from perforations (system intake node) to wellhead outlet (system output node). That will enable to determine:

- The most effective coiled tubing size to install
- Optimum setting depth of coiled tubing
- Incremental production response

Once the well is a potential candidate the relationship between flow rate and bottomhole flowing pressure are developed. The conditions that are considered are coiled tubing size, tubular weights, tubular depths, surface pressure, temperature, gas flow rate, liquid flow rate and liquid makeup. The result is a tubing performance curve and is generated through the solution of the equation:

$$\frac{dp}{dz} = \left(\frac{dp}{dz} \right)_{el} + \left(\frac{dp}{dz} \right)_{fr} + \left(\frac{dp}{dz} \right)_{acc} \qquad (3)$$

Where:

dp/dz – pressure drop in coiled tubing, Pa
$(dp/dz)_{el}$ – pressure drop due to elevation change, Pa
$(dp/dz)_{fr}$ – pressure drop due to friction, Pa
$(dp/dz)_{acc}$ – pressure drop due toacceleration, Pa

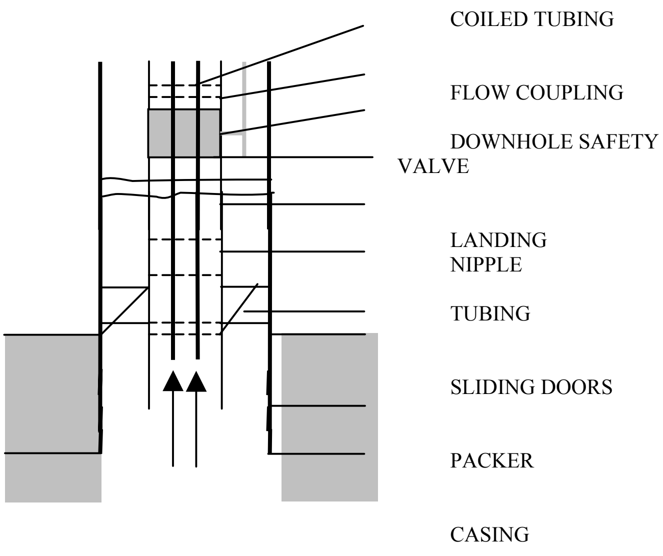

Fig 1. Coiled tubing as a velocity string

To get a realistic tubing performance curve it is important to ensure that the input variables are as realistic as possible.

The second half of the system is the reservoir. To describe the hydraulic performance of the reservoir the most common is the back pressure equation (Adams, L.S., 1993.):

$$q = C \cdot \left(p_r^2 - p_{wf}^2\right)^n \qquad (4)$$

Where:

q – production rate, m^3/day
p_r – average reservoir pressure, Pa
p_{wf} – well flowing pressure, Pa
C – performance coefficient from well data
n – exponent obtained from well tests

(C) and (n) can be calculated from a log-log plot of (q) versus (p_r^2 – p_{wf}^2), through a four-point back-pressure test, and in equation form as:

$$\log q = \log C + n \cdot \log\left(p_r^2 - p_{wf}^2\right) \tag{5}$$

On the log-log plot (n) is often refered to as slope of the line and (log C) as the Y-intercept and in reality (n) is the reciprocal of the slope of the plotted line, and (C) is equql to the value of (q) when (p_r^2 – p_{wf}^2)=1. The value of (n) can be determined from:

$$n = \left(\log q_2 - \log q_1\right) \Big/ \left(\log\left(p_r^2 - p_{wf}^2\right)_2 - \log\left(p_r^2 - p_{wf}^2\right)_1\right) \tag{6}$$

The relationship between the flow rate and flowing bottomhole pressure is called an inflow performance relationship curve.

Coiled tubing selection

The size and length of coiled tubing my be dictated by previous pipe instalation. Optimal can be externally tapered coiled tubing because of flexibility for optimizing flow. The following design parameters of coiled tubing string should be reviewed:

- Minimum and maximum tensile load, burst and collapse pressure allowed.
- Desired over pull above string weight of each segment before yield load is obtained.
- Based on wellbore trajectory sinusoidal or helical buckling, pickup and slack-off loading evaluation.
- Metallurgy that can ensure suitable material for desired time exposure in the well's downhole environment.
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A procedure of typical coiled tubing velocity string hang off implements:

- Removal of paraffin or other obstruction if needed
- The way of liquid removal
- Christmas Tree preparation: closing of lower master valve, bleeding of pressure above lower master valve, removing Christmas tree above lower master valve
- Instalation of coiled tubing hanger, instalation of packoff assembly in hanger and locking
- Riging up the coiled tubing unit, instalation of window and blowout preventers
- Installing pumpout plag in coiled tubing, opening master valve and running in hole to desired depth
- Landing coiled tubing, installing slips and packoff, cutting tubing in window; re-cutting after rigging down coiled tubing unit
- Instalation of Christmas tree on coiled tubing hanger, pumping out plug to enable production

Conclusion

Liquid loading of gas wells should be identified and resolved as early as possible. Installation of coiled tubing is now proven alternative. Since this is typically packerless completion coiled tubing and annular pressure can be monitored to ensure that stable flow is occuring. Indication of unstable flow is the fluctuation of annular pressure.

References

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