When Should Artificial Lift Be Installed on a Well

By NORMAN LAMONT
University of Texas

INTRODUCTION

Every producer longs to get a well which produces by natural flow when he drills his well. The reasons are quite clear: the costs of installation, equipment and operation are considerably less than for any artificial lift method which could be installed. In spite of these obvious advantages, there are few references to be found that concern themselves with the flowing well. The paucity of material is probably due to two causes:

1. As no equipment can be sold or serviced, few manufacturers or suppliers will devote their finances and energies to such research. Nor can they be blamed for this.
2. The flowing wells completed in Texas each year are a small minority of total completions. Thus the larger, immediate problems of artificial lift overshadow those of flowing wells.

Any given well, upon completion, may flow initially. However, this condition may not last for the life of the well. In fact, it will not do so in the majority of cases. It is the purpose of this paper to present some methods of predicting the flow life of a well so that artificial lift can be installed at an optimum time.

THE FLOWING WELL

A flowing well consists of three separate and distinct, though connected, flow systems. The first is the reservoir-well bore system; the second is the vertical flow system; and the third is the choke, or bean, system in the well head or flow arms.

The Reservoir-Bore Hole System

The ability of the well system to produce oil in commercial quantities depends ultimately on the ability of the reservoir to allow oil to flow into the well bore. This flow, of course, is expressed by the well known Darcy equation, which can be written for horizontal flow as

$$Q_o = \frac{k_o A}{\mu_o} \frac{d P_o}{dx}$$

$$Q_g = \frac{kg}{\mu g} A \ \& \ \frac{Pg}{dx}$$

The subscripts denote the fluid flowing.

Allied with these are the ratio equations which are necessary when two fluids are flowing simultaneously into the bore hole. These are

$$\text{WOR reservoir} = \frac{Qw}{Qo} = \frac{kw}{ko} \quad \frac{\mu o}{\mu W}$$

$$\text{GOR reservoir} = \frac{Qg}{Qo} = \frac{kg}{ko} \quad \frac{\mu o}{\mu g}$$

and both are at reservoir conditions. Since this part of the well system under consideration is at elevated pressures, the form of the equation at the surface will not be considered.

To use these equations to predict rates of flow, it is evident that the following must be known:

1. the physical properties of the fluids, mainly viscosity (μ);
2. the permeability of the rock to each fluid flowing (k);
3. the pressure history of the reservoir and the formation face; and
4. the type of drive mechanism of the reservoir.

The physical properties of fluids can best be measured on samples obtained at reservoir conditions. When this is not possible, surface samples can be obtained and recombined at reservoir conditions in the laboratory.

The viscosities of water and gas are functions of pressure and temperature. In this part of the system, however, the flow is probably isothermal, and temperature variations can be neglected. The oil viscosity is a function of these two, plus the amount of gas dissolved in the oil. It, in turn, is a function of the pressure to which the oil is subjected at the time in question, and of the original gas in solution.

The permeability of a rock, with multiple fluids in the pores, to one of the fluids is called the effective permeability to that fluid and is usually designated by a subscript denoting the fluid, e.g., k_o means effective permeability to oil. This is always less than the absolute permeability of the rock (k). The effective permeability divided by the absolute permeability gives relative permeability, which is a value between zero and unity. While absolute permeability is a rock property, effective permeabilities depend upon the fluids present and the amount of pore saturation of each. To make these measurements, it is necessary to have a sample of the rock, as well as fluid samples. These measurements are difficult to obtain in the laboratory and the validity of the results of such measurements is often questioned.

Rate Of Flow

The rate of flow into the well bore is dependent upon the pressure gradient in the system. This means the pressure at the outer flow boundary, usually called reservoir pressure, the pressure in the well bore at the face of the formation, and the distance between these two. In a radial system, the latter would usually be expressed in terms of the reservoir and well radii.

In most reservoirs, the pressure declines with time as the oil, gas, and water are produced. This means the pressure variables in the flow equations change with time causing the rate of flow of oil to decrease with time. The gas/oil ratio, at the same time, would generally increase. The oil rate could be maintained at a high level if the well pressure could be lowered to give a sufficiently large pressure differential to offset changes in permeability and viscosity in the Darcy equation.

Such a measure would have two immediate and evident results. First, the flow of gas and/or water would increase with resulting higher ratios. Second, the lower bottom hole pressure would result in a reduced rate of vertical flow from the bottom hole since the rate of flow is dependent on a pressure drop up the flow string. The maximum inflow rate would be achieved when the bottom hole pressure was atmospheric. But the vertical flow would be zero. Thus, these two parts of the well system have opposing requirements for flow to be maintained.

The Vertical Flow System

The vertical flow system consists of the casing between the inflow face and the tubing and the tubing itself. Since the former is relatively short compared to the letter, it will be ignored and the tubing will be considered to be the controlling medium. The rate of flow through the tubing is a function of the tubing diameter, the tubing length, the inflow and outlet pressures and the input gas/liquid ratio. In a flowing well, the depth pressure gradient is not constant because there is two phase flow occuring in the string and the type of flow changes up the string.

The Bean System

The bean or orifice is installed at the surface outlet of the tubing to control the rate of production. Generally speaking, the rate of production increases as the bean size increases, but not in a direct ratio. It is also interesting to note that production rate increases are larger at higher gas/liquid ratios as the bean size is increased.

WHY PREDICT FLOWING LIFE?

The reasons for desiring to know when a well will cease to flow are many and can generally be classified as economic. For example, there is the loss of production while the well is being restored to flow or while artificial lift is being installed. Another example would be to know when the flowing capacity would drop below the top allowable for the well. This is probably more important than any other reason. Still another reason is the inability of an operator to carry excessive artificial lift equipment on inventory. Generally, the larger the company, the better able it is to carry such inventory. However, money thus expended is not available for other uses.

This knowledge can be of extreme importance in reservoirs of the differential depletion type, i.e., where different stringers are being produced and are at different stages of depletion. When the well dies, the depleted stringers are invaded by the well fluid. This could result in lost oil, particularly if the well is producing some water. This suggests that such wells should always be produced on a calendar day basis rather than on a producing day basis.

Occasionally, high gas/oil ratio, high pressure, low productivity wells are penalized due to excessive gas/oil ratios during latter life when flow is by heads. Installation of artificial lift at the proper time could reduce the GOR and save this lost production.

HOW TO PREDICT FLOWING LIFE

The preduction of the flowing life of a well is dependent upon past performance of the well. Rigorous measurements of the properties mentioned earlier are seldom available for each well, although a sampling of several wells in the field would certainly be advisable. The productivity of the well is measured or gauged by its productivity index (PI) which is the ratio of the production of oil in stock tank barrels per day and the pressure differential between the reservoir and the well bore, or

$$PI = \frac{Qo}{(Pe-Pw)} \quad \text{bbls/day/psi.}$$

To be meaningful, the flow must be at stabilized conditions or PI should be a constant.

The performance is frequently depicted graphically to show (1) static (shut-in) pressure at the midpoint of the producing interval, (2) maximum gross inflow rate, (3) gas/liquid ratio and (4) water cut plotted as functions of cumulative oil withdrawals. The trends of the curves are projected into the future.

The most commonly used method, probably, is an engineering comparison. This involves comparing a well's performance with other wells in the area which have ceased flowing. This works very well with short-lived wells, and will give close estimates of the flow life. To be considered, the wells must be producing under similar conditions.

A second method was proposed by W. E. Gilbert in his paper before the API in 1954. Basic to this method is the past performance of the well, as mentioned above. The first step is to establish the relation between static well pressure at the mid point of the interval and the rate of production. This will be dependent upon tubing diameter, gas/liquid ratio, depth of production and the two phase pressure gradient.

The next step is to calculate and plot the estimated static pressure rate of production curves from the cumulative withdrawals curves, considering PI and gas/liquid ratios.

The bottom hole pressure necessary to cause flow at the surface, in a two phase system, can be calculated by knowing the depth pressure gradient. By use of the gradient figures of Poettman and Carpenter, curves can be calculated indicating the intake pressures necessary to sustain lift with the known tubing pressure for a series of gas/liquid ratios which cover the predicted gas/liquid ratios. These curves are superimposed on the graph of step two.

The well's progress is then plotted on this combined graph by interpolating points using the predicted gas/-liquid ratios. When this curve becomes tangent to one of the rate pressure curves, flow ceases.

To predict the time, an average rate of production is selected for the increment of cumulative production and the days are calculated. The sum of the time periods for the total production to the point of tangency above gives the estimated flow life of the well.