BASIC HYDRAULICS AS THEY AFFECT PACKER CALCULATIONS AND APPLICATIONS

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INTRODUCTION

Packers are run in oil and gas wells primarily to confine fluids. Usually the objective is to confine high-pressure or corrosive fluids and/or, in the case of multiple completions, to confine the fluid to specific tubing strings. Many side benefits are obtained because of the confinement; such as, protection of the casing from high-pressure or corrosive fluids, separation of zones in the well bore, directing the flow of treating fluid, and also as a safety feature.

Various questions always arise; e.g., how much weight to set on the packer, how much do you pull, how much psi will it hold, how much do you pull to release the packer?

There are a number of computer programs that have been written to analyze and predict tubing and packer loading forces and tubing movement. The computer certainly has its place, especially in the deeper wells where the conditions become more extreme and critical and the calculations become more complex. However, most applications can be quickly and accurately analyzed by applying a few basic calculations to determine the net result of the various operating conditions.

Quite often it is possible to rely on an experience factor to design a hookup; but for more extreme conditions, the present and future well conditions should be anticipated and a hookup designed that would be compatible with these operations.

This discussion will concern itself with calculations involving the hydraulics and various other forces as they affect packers. An attempt will be made to focus the emphasis on calculations that can be readily made at the wellsite without sacrificing accuracy. It would be oversimplifying the subject to say that all packer application problems are pressure and area calculations; but many of the calculations simply involve pressure and area. A little further in this discussion we will touch on tubing movement calculations involving piston (axial), helical buckling (corkscrewing), ballooning (radial) and temperature (axial). In a total analysis, many complex theories are utilized but that is not the purpose of this paper.

APPLICATION

Forces normally include the weight of the tubing, the applied force whether compression or tension at the surface, or hydraulic (pressure times area) force. The areas are dictated by the size of tubing and casing and the packer configuration. Both hydrostatic and applied pressure are measured in pounds per square inch (psi); to arrive at the total force, multiply the pressure times the affected area.

Hydrostatic pressure is created by the weight of a column of fluid. Fluid weight information commonly used in the field is in lb/gal. To figure hydrostatic pressure, use the number 0.052 times ppg times depth. The figure 0.052 is the psi/ft for one ppg water. When this figure is multiplied by ppg, the result is the psi/ft or fluid gradient for that weight fluid. Multiplying the fluid gradient times depth gives the hydrostatic pressure for that depth.

Applied pressure, which is put into the system with a pump, will be found (neglecting friction) throughout the system. Applied pressure is added to the hydrostatic pressure at any depth.

It is a frequent requirement to balance two columns of fluid (tubing fluid and casing fluid) in a well. This is accomplished by using the fluid gradient and depth and applying pump pressure to the proper column. In the case of a low fluid level well, it may be necessary to convert the required pressure into height of fluid or into the number of barrels required to fill the pipe to a specified level to obtain a given pressure.

Many actual packer calculations involve only the forces across the packer. It is necessary to calculate the expected or anticipated changes in pressure or conditions to determine the initial setting force, either tension or compression, depending upon the type of packer, and the pressure limitations of the particular application. Forces across the packer are primarily caused by pressure changes and are commonly referred to as piston forces; simplified, this means the result of pressure acting on horizontal exposed areas, and calculations are handled as if the packer were a piston. The pressure change may be the result of an applied pressure, fluid density change, fluid level change or a combination of these.

Remember that, normally, when a packer is set it is in equilibrium and the forces across the tool are balanced. It is important when solving packer problems that all changes are calculated from the initial conditions. In actual practice, there will probably be two or more different conditions associated with the particular well involved. These varied conditions are handled as separate problems and the starting points are the initial conditions. It is usually helpful, if not necessary, to make a sketch of the tubing and packer to properly determine the direction of the forces.

For example, consider a common installation for West Texas. Assume an injection well equipped with 7-in., 23 lb/ft ($Ai = 31.83$ in.^{2}) casing, 2-7/8 in. 6.5 lb/ft ($Ao = 6.49$ in^2) tubing, a tension-type hookwall packer with an initial tension of 18,000 lb, and the fluid level at the surface. The tension packer is designed for pressure operations below the packer but only limited pressure from above. It is desired to pressure test the casing above the packer and the question is how much pressure can be applied to the annulus.

$$\frac{\text{Applied Tension}}{\text{Differential Area}} = \frac{18{,}000 \text{ lb}}{(31.83 - 6.49) \text{ in.}^2} = 739 \text{ psi}$$

Thus 739 psi can be applied to the annulus before it will overcome the initial tension and begin to start the tool down the hole.

Consider an example when it is desired to know the hook load or weight indicator reading to release a packer. Assume the well is equipped with a permanent type packer with seals that are free to travel upward. Calculate the weight of the steel in the tubing; then calculate the pressures at the packer pushing either up or down multiplied by the affected areas and the result will be the hook load. When the tubing is larger than the bore of the packer, the casing pressure pushes up on the tubing and the tubing pressure pushes down and if the tubing is smaller than the packer bore, the casing pressure pushes down and the tubing pressure pushes up. Often it is not necessary to consider the hook load. For instance, if it were desirable to know how much weight to set off on the packer to hold a specific tubing pressure (assume the tubing is smaller than the bore) proceed by multiplying the expected pressure by the difference in area between the tubing ID and the packer bore ID. Since this figure is an upward force, set this amount of weight down on the packer.

Tubing movement is described by four equations as reported by Lubinski, Althouse and Logan.[1] These equations are shown in Table 1 in a slightly modified form.

Each of the equations, with the exception of the buckling equation, is converted and expressed in units of force. It is also interesting to note that the force equations (except buckling) are all straight-line functions of a pressure or temperature differential. This makes the construction of graphs[2] a rather simple task and if a series of graphs were constructed, the graphic technique could be utilized to solve for forces with varying pressures and temperatures.

The total tubing movement is the algebraic sum of the four factors. A positive length change indicates an upward movement of the lower end of the tubing and a negative length change indicates a downward movement.

Usually it is less confusing to make the calculations and attach arrows to signify the direction of the length and/or force changes. It is also important to be familiar with the mechanics of the packer. For example, (assume the well is equipped with a permanent-type packer) if the lower end of the tubing is free to move upward, then a positive ballooning force indicates that the packer seals are moving upward; but if the lower end of the tubing is locked in then a positive ballooning force loads the packer in tension and it also loads the tubing in tension. Now if the piston force was positive and the lower end of the tubing was free to move, the tubing would move upward and also sense a compressive force. If the lower end of the tubing was locked in, the packer would absorb the piston force. To calculate the piston effect and assuming the fluid levels and fluid densities have not changed, the only data needed would be the appropriate areas and the applied surface pressures. The data needed for the buckling calculations can be obtained from published tables with the exception of the pressure changes and these changes are the changes in pressure at the packer from original conditions.

The ballooning calculations involve tubular data and the average change in pressure. The thermal or temperature effect is very often the major contributor to the total tubing movement or force change. Steel responds to a change of temperature by expanding if the temperature is increased or contracting if the temperature is decreased. An article by Ramey[3] delved into the subject of the

TABLE 1

LENGTH AND FORCE CHANGES IN TUBING

LENGTH CHANGES (all in inches)

1. Piston Effect

$$\Delta L_1 = \frac{L}{EA_s}\left[(Ap - Ai)\ \Delta Pi - (Ap - Ao)\ \Delta Po\right]$$

2. Buckling Effect

$$\Delta L_2 = \frac{r^2Ap^2(\Delta Pi - \Delta Po)^2}{8EI\,(W_s + W_i - W_o)}$$

3. Ballooning Effect

$$\Delta L_3 = \frac{2L}{10^8}\left[\frac{\Delta Pia - R^2\Delta Poa}{R^2 - 1}\right]$$

4. Temperature Effect

$$\Delta L_4 = L\,\beta\,\Delta t$$

FORCE CHANGES (all in pounds)

1. Piston Effect

$$F_1 = (Ap - A_i)\ \Delta Pi - (Ap - A_o)\ \Delta Po$$

2. Buckling Effect (This effect can shorten tubing, but can exert only a negligible force.)

3. Ballooning Force

$$F_3 = .6\,(\Delta PiaA_i - \Delta PoaA_o)$$

4. Temperature Effect

$$F_4 = 207\ A_s\Delta t$$

TOTAL SLACKOFF

$$\Delta L^1 = \frac{LF}{EA_s} + \frac{r^2F^2}{8EI\,(W_s + W_i - W_o)}$$

LENGTH AND FORCE CHANGES IN TUBING

TERMS

L = Depth in *inches*

E = Modulus of elasticity 30,000,000 psi for steel

A_s = Cross-sectional area of tubing*

A_p = Area of Packer ID

A_i = Area of tubing ID*

A_o = Area of tubing OD*

ΔP_i = Change in tubing pressure *at packer*

ΔP_o = Change in annulus pressure *at packer*

ΔP_{ia} = *Average change* in tubing pressure

ΔP_{oa} = *Average change* in annulus pressure

r = Radial clearance between tubing OD and casing ID $(ID_c - OD_t)/2$

I = Moment of inertia of tubing about its diameter*

W_s = Weight of tubing *per inch**

W_i = Weight of fluid in tubing (lb/in)*

W_o = Weight of displaced fluid (lb/in)*

R = Ratio of tubing OD to ID*

β = Coefficient of thermal expansion (.0000069 in/in/°F for steel)

*Given in chart for common sizes and weights

For extreme conditions, basic formulas and derivations, see *"Helical Buckling of Tubing Sealed in Packers,"* Arthur Lubinski, W. H. Althouse, Jr., and J. L. Logan, **JOURNAL OF PETROLEUM TECHNOLOGY**, June, 1962.

TABLE 2

TUBING CONSTANTS						
OD IN (Inches)	WT. IN (Lbs/Ft)	A_o IN (Sq. In.)	A_i IN (Sq. In.)	A_s IN (Sq. In.)	I IN ($In.^4$)	R^2
1.660	2.40	2.164	1.496	.668	.195	1.448
1.900	2.90	2.835	2.036	.799	.310	1.393
2.000	3.40	3.142	2.190	.952	.404	1.434
2-1/16	3.40	3.341	2.405	.936	.428	1.389
2-3/8	4.70	4.430	3.126	1.304	.784	1.417
2-7/8	6.50	6.492	4.680	1.812	1.611	1.387
3-1/2	9.20	9.621	7.031	2.590	3.434	1.368

$w_s + w_i - w_o$														
Tubing OD (Inches)	Weight (Lbs/In.)	w_i and w_o (Lbs/In.)	7.0 52.3	8.0 59.8	9.0 67.3	10.0 74.8	11.0 82.3	12.0 89.8	13.0 97.2	14.0 104.7	15.0 112.2	16.0 119.7	17.0 127.2	18.0 134.6	Lbs/Gal. Lbs/Cu. Ft.
1.660	w_s = .200	w_i	.045	.052	.058	.065	.071	.078	.084	.091	.097	.104	.110	.116	
		w_o	.065	.075	.084	.094	.103	.112	.122	.131	.140	.150	.159	.169	
1.900	w_s = .242	w_i	.062	.070	.079	.088	.097	.106	.115	.123	.132	.141	.150	.159	
		w_o	.086	.098	.110	.123	.135	.147	.159	.172	.184	.196	.209	.221	
2.000	w_s = .283	w_i	.066	.076	.085	.095	.104	.114	.123	.133	.142	.152	.161	.171	
		w_o	.095	.109	.122	.136	.150	.163	.177	.190	.204	.218	.231	.245	
2-1/16	w_s = .283	w_i	.073	.083	.094	.104	.114	.125	.135	.146	.156	.167	.177	.187	
		w_o	.101	.116	.130	.145	.159	.174	.188	.202	.217	.231	.246	.260	
2-3/8	w_s = .392	w_i	.095	.108	.122	.135	.149	.162	.176	.189	.203	.217	.230	.243	
		w_o	.134	.153	.172	.192	.211	.230	.249	.268	.288	.307	.326	.345	
2-7/8	w_s = .542	w_i	.142	.162	.182	.203	.223	.243	.263	.284	.304	.324	.344	.364	
		w_o	.196	.225	.253	.281	.309	.337	.365	.393	.421	.450	.478	.506	
3-1/2	w_s = .767	w_i	.213	.243	.274	.304	.335	.365	.395	.426	.456	.487	.517	.548	
		w_o	.291	.333	.365	.416	.458	.500	.541	.583	.625	.666	.708	.749	

effect of injected fluid on the temperature of the tubing. Normally, produced fluids tend to warm the tubing and injected fluids tend to cool the tubing. For the sake of brevity, only injected fluids will be considered here. To calculate the average temperature change to substitute into the formula, the average static temperature and the average injection temperature of the tubing are needed. The static average is the average of the mean yearly temperature and the bottomhole temperature. The average injection temperature of the tubing is the average of the injected fluid temperature at the surface and at the bottom of the hole. The temperature at the bottom is dependent on the fluid temperature, injection rate and the injection time period. It is an accepted practice to assume that the lower end of the tubing is the same temperature as the injected fluid because if the rate is a low as 2 BPM for a period of 6 hours or 6 BPM for 1 hour, then the lower end of the tubing approaches the temperature of the injected fluid.

SUMMARY

Many oil, gas and injection wells are equipped with packers. The installations are quite varied and the calculation of the varied forces affecting the installations can be a very complex subject.

This presentation reviewed a few of the basic calculations involved in designing and/or analyzing a packer application or installation.

REFERENCES

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