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Preface

This thesis completes my Master degree in Petroleum Engineering with specialization in Drilling Engineering.

I give my best thanks to my supervisor Jan Aage Aasen for always being there when I needed guidance, always giving a quick response to emails and telling me which direction to go when I was lost. It has truly been an honor to be supervised by him.

I also wish to thank my family for the support they have given me throughout my studies by always believing in me.

Finally I want to thank my fellow students for the help they have given me when units were tough, the friendship and all the good times. Even though many of them start working for different companies at different locations, the memory of them and the good times we had will last forever. Without them the studies would have been meaningless.

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Nomenclature

A_a = Area of annulus, area between the casing and the tubing

A_i = Inner area of the tubing

A_o = Outer area of the tubing

A_p = Area of the packer bore

A_{pb} = Area of the packer body

A_s = Steel area of the tubing = A_o-A_i

A_w = Area of the wellbore, area inside the casing

BL = Buckling limit

D_i = Inside diameter of the tubing

D_o = Outside diameter of the tubing

E = Young's modulus of elasticity (for steel, E= 31038000 psi)

F = Piston force/buckling force

F_a = Force actual, same as force real, the force that actually can be felt, true weight below the point the of interest

F_{ah} = Axial load at tubing hanger

F_{ahel} = Available force for helical buckling

F_{alat} = Available force for the lateral buckling

F_{atra} = Available force for the transition buckling

F_E = Fictitious force, same as F_f, the buckling force

F_f = Fictitious force, the buckling force

F_{fp} = Fictitious force just above the packer

F_{fts} = Fictitious force at the top of the sail section

F_{fs} = Gradient of the fictitious force in the sail section, change in fictitious force per unit length

F_{fz} = Gradient of the fictitious force in the vertical section, change in fictitious force per unit length

F_h = Hooke's force, the force needed to stretch the tubing back to the packer position

F_p = Piston force working on the steel area below the tubing

F_{pb} = Packer body force

F_{p2c} = Force packer to casing

F_R = Real force, same as force actual, the force that actually can be felt, true weight below point the of interest

F_{t2p} = Tubing to packer force

$F_{t2p\ old}$ = Tubing to packer force after the hydraulic packer is set and the pump pressure is zero.

HBL = Helical buckling limit

I = Moment of inertia =PI/64*(Do^4-Di^4)

LB_i = Buckled length for i=1,2,3 where 1=lateral, 2= transition and 3 = helical

LB_s = Length of the buckled tubing in the sail section

LB_t = Total buckled length

LB_v = Length of the buckled tubing in the vertical section

L_t = Length of tubing between tubing hanger and packer

L_{th} =Length of tubing in the helically buckled section

L_{tl} =Length of tubing in the laterally buckled section

L_{tt} = Length of tubing in the transition from helically to laterally buckled section

MD = Measure depth at a chosen point

MD_p = Measure depth at packer depth

n = neutral point

P = Pressure at a given depth

P_{bt} = Pressure below the tubing

P_i = Pressure inside of the tubing

P_o = Pressure outside of the tubing

P_p = Pump pressure in psi

R = Ratio OD/ID of the tubing

r = Radius of curvature, inch

R_c = Tubing to casing radial clearance

S_i = Length fractions of the different type of buckling, i=1,2,3 where 1=lateral, 2= transition and 3 = helical

TVD = True vertical depth at a chosen point

TVD_h = True vertical depth at the tubing hanger

TVD_p= True vertical depth at the packer

v = Poisson's ratio of the material (WellCat v = 0,27)

w = Buoyed weight of the string per unit length, in air w equals w_s

w_{bp} = Buoyed weight of the string, lbs/inch

w_i = Weight of the liquid inside the string per unit length

w_o = Weight of the outside fluid displaced by the string and the fluid inside the string

w_s = Weight of the tubing in air per unit length

α = Inclination angle from vertical, rad

β = Coefficient of thermal expansion of the tubing material, for steel $\beta = 6{,}9 \cdot 10^{-6}/1°F$

δ = Pressure drop per unit length due to flow

ΔF = The net change of piston forces inside and outside the tubing

ΔL_1 = Length change of the tubing due to Hooke's law

ΔL_2 = Length change due to helical buckling

ΔL_{2sl} = Length change due to lateral buckling for a sail section, inch

ΔL_{2sh} = Length change due to helical buckling for a sail section, inch

ΔL_3 = Length change due to radial pressure forces and flow through the tubing

ΔL_4 = Length change of the tubing due to temperature change

ΔL_5 = Length change due to slack off or pick up before pressure, temperature, density change and flow

ΔL = Total length change of the tubing due to initial slack off or pick up followed by pressure temperature and density changes

ΔP_i = Change of pressure inside the tubing at packer level from initial condition to final condition

ΔP_o = Change of pressure outside the tubing at packer level from initial condition to final condition

ΔF_P = Delta piston force (working on the steel area below the tubing)

Abbreviations

BHT = Bottom hole temperature

TVD = True vertical depth

MD = Measure depth

PBR = Polish bore receptacle

HBL = Helical buckling limit

BL = Buckling limit

CT = Coiled tubing

DLS = Dog leg severity

KOP = Kick off point

SDW =Set down weight

BU = Build up section

RKB = Rotary kelly bushing

DO = Drop off section

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Abstract

New discoveries could represent challenges in many ways such as high pressures and high temperatures. The reservoir contains corrosive liquids that are being produced to the surface. Since the casing is expensive to replace, it is common practice to flow the reservoir fluid through a protective tubing. Also the tubing and packer are part of the primary well barrier. Change of temperature and pressure can make the tubing buckle. When wells need intervention, for instance to repair some type of damage or to increase the production, intervention equipment run through the tubing could get stuck in the buckled section.

This thesis will study buckling of tubing in vertical wells and sail sections for frictionless wells. By using theory, theoretical field cases and reverse engineering this thesis reveals the equations used by the buckling simulation software called WellCat 2003.0.4.0 from Landmark.

The fictitious force, also known as the buckling force, is discussed in details. The buckling limit used by WellCat is found, showing that the simulator performs very conservative buckling calculations. Buckling is less severe in sail sections than in vertical sections. The effect of inclination of the sail section on the piston effect, helical buckling length change and ballooning effect is shown for a mechanical set packer.

Chapter 1

Introduction

This thesis studies the equations to calculate the packer forces and the buckled length of the production tubing used by the buckling simulation software WellCat 2003.0.4.0 from Landmark. Well friction is neglected. Four theoretical field cases have been studied. Vertical well with mechanical and hydraulic set packer, deviated well with mechanical and hydraulic set packer.

1.1 Background of the thesis

As seen in Figure 1 there are two ways a pipe can buckle, sinusoidal or helically. In a vertical well the pipe buckles helically after making a single point contact with the surrounding wall [1]. In a sail section the pipe buckles first snake like. If enough energy is present in the pipe to lift the pipe up against the casing wall, helical buckling occurs. There is also transition between the two types of buckling.

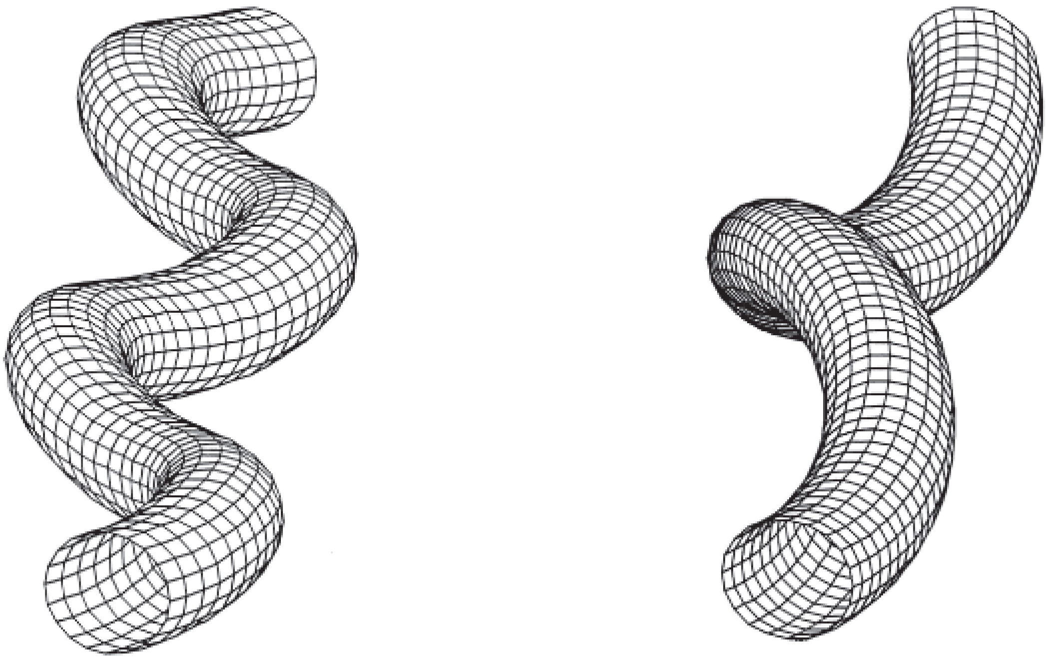


Figure 1. Sinusoidal and helical buckling deformation [2].

1.2 Study objective

The objective of this work is to reveal the equations used by the buckling simulator WellCat 2003.0.4.0 to calculate axial force, length changes of the tubing, packer forces, buckled length of the tubing for frictionless wells and determine which helical buckling limit the simulator uses. Buckling for theoretical field cases are calculated for vertical and deviated wells with mechanic and hydraulic set packer.

1.3 Report structure

Chapter 2 explains the fictitious force, real force and the piston force. These parameters are important in order to understand the basic concepts of buckling. The different types of length changes for some types of packer concepts are also presented in this chapter.

Chapter 3 explains the equations used for calculating packer forces and buckled length for mechanic and hydraulic set packers. The results for the theoretical field cases for chapter 3 are presented in Appendix A and B. They focus on mechanic and hydraulic set integral packers in vertical wells.

Chapter 4 introduces the equivalent height concept, equations to calculate the buckled length for the sail section in frictionless wells. A table of buckling limits developed by various researchers is presented and the buckling limit used by WellCat is found. Equations for calculating the length change due to helical, transition and lateral buckling in sail sections are presented. The results for the theoretical field cases for chapter 4 are presented in Appendix C and D. They focus on mechanic and hydraulic set packers in sail sections for frictionless wells. Further an analysis on the behaviour of the length changes and the buckled length on sail angle is conducted and discussed. A sensitivity analysis of the behaviour of the length changes and the buckled length for small angles is conducted and the WellCat result is compared to the equation presented in the thesis.

Finally, the conclusion is given based on the observations and the theory presented.

Chapter 2: Packer force theory

The focus in this chapter is to understand the fictitious force, also called the buckling force, the piston force and the different type of length changes of the tubing. Also different packer concepts are presented.

2.1 Real force and fictitious force

The fluids that are produced from the reservoir to the surface normally flows through a tubing which is placed inside of the casing string. The annulus, the space between the casing and the tubing, is sealed off with a packer. The packer can either be set mechanically or by applying pressure for hydraulic and hydrostatic set packers. The tubing is subject to pressure forces. When the pressure forces are changed the tubing can shorten and elongate due to the elasticity of steel. Also change in temperature plays a big role in changing the length of the tubing. After the packer is set and the production has started the tubing is subject to different pressure and temperature than it was before the packer was set. If the tubing is allowed to move the length of the tubing could change. If the tubing is fixed and not allowed to move freely, the packer could be subject to additional forces. If the net force on the packer is to big the packer could fail causing leakages and need for a costly work over operation. In 1962 Arthur Lubinski et. al. [3] published equations for calculating the length changes of the tubing caused by the change of pressure and temperature. The theory and equations is repeated as a background for the theoretical field cases in the thesis.

We define an elongation of the string as positive (+) and shortening negative (-). Further, a tension force is positive (+) and a compression force is negative (-). Consider the string shown in Figure 2 (a).

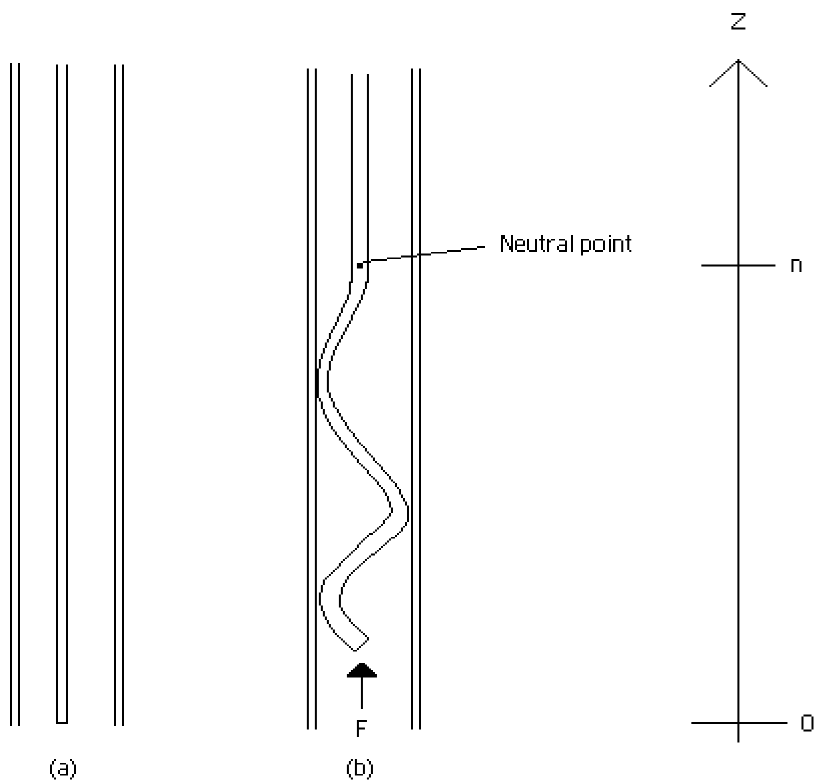


Figure 2. Buckling of tubing [3].

Applying a large enough force on the bottom of the string in the upward direction will make the string buckle into a helix as shown in Figure 2 (b). The force F is compressive. The point where the string transforms from buckled to straight is called the neutral point. The neutral point in a vertical well can be found by [3]:

$$n = \frac{F_f}{w} \tag{2.1}$$

Where Ff is the fictitious force given by:

$$Ff(z) = F_R(z) + A_o P_o(z) - A_i P_i(z) \tag{2.2}$$

And the buoyed weight per unit length is given by [3]:

$$w = w_s + w_i - w_o \tag{2.3}$$

Where w_s is the weight of steel per unit length, w_i is the weight of the fluid inside the pipe per unit length and w_o is the outside weight of the fluid per unit length. P_i and P_o is the inside and outside pressures. A_i and A_o is the inside and outside pipe area. For a vertical well buckling occur when the fictitious force is less than zero (compression). In an inclined well buckling occurs when the fictitious force is less than the buckling limit (BL). The fictitious force depends on the true vertical depth (TVD). The real force, F_R, is the axial force at a point that would be needed in order to keep the tubing from falling. In our case the real force at bottom is a compression force that is negative. Moving upward the string, the weight of the string hanging below it will increase the real force. At some point the real force changes from negative to positive, meaning that the string goes from compression into tension. Even though the real force is zero, the pressure inside the tubing can make it buckle if it is high enough. On the other hand, if the pressure outside of the tubing is high enough compared to the inside pressure buckling is prevented.

Consider a string submerged in a liquid as shown in Figure 3:

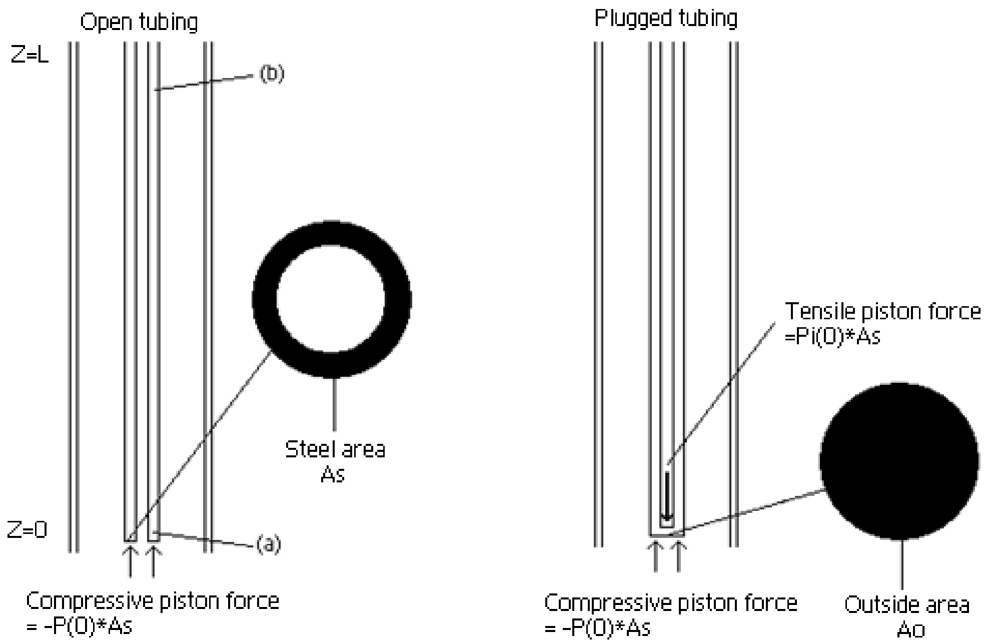


Figure 3. Open and plugged tubing submerged and filled with liquid.

The liquid pressure acting on the bottom of the tubing (Z=0) on the steel area creates a compressive piston force. At point (a) in Figure 3 F_R is negative and the tubing is actually in compression. At point (b), F_R is the piston force plus the weight of the tubing:

$$F_R(L) = F_R(0) + w_s * L \quad 2.4$$

$$F_R(b) = -P_{bt}A_s + w_s * L \qquad \text{(open tubing)} \quad 2.5$$

$$F_R(b) = -P_{bt}A_o + P_iA_i + w_s * L \qquad \text{(plugged tubing)} \quad 2.6$$

As one travel along the tubing from the bottom, F_R will become zero (neither in compression nor tension) and above that point the tubing is in tension.

If the tubing is open and the pressure inside pressure changes there will be a change in piston force:

$$\Delta F_P = A_s \Delta P_i \quad 2.7$$

For the open tubing case the fictitious force at the bottom is (Z=0):

$$Ff(0) = F_R(0) + A_oP_o(0) - A_iP_i(0) \quad 2.8$$

$$= -P_{bt}A_s + w_s * 0 + A_oP_o - A_iP_i\,, \; P_i = P_o = P_{bt} \quad 2.9$$

$$= -P_{bt}A_s + w_s * 0 + P_i(A_o - A_i) \quad 2.10$$

$$= -P_{bt}A_s + w_s * 0 + P_{bt}A_s = 0 \qquad (open\ tubing) \quad 2.11$$

The pressure inside and outside of the tubing is the same. This shows the important fact that when a pipe is submerged into a liquid and filled inside with the same liquid, the pipe will never buckle. Moving upwards the string the F_R will increase and the inside and outside pressure will decrease. However, because steel is denser than drilling fluids the fictitious force becomes a tension force moving upwards from the bottom and the pipe remains straight all the way to the top.

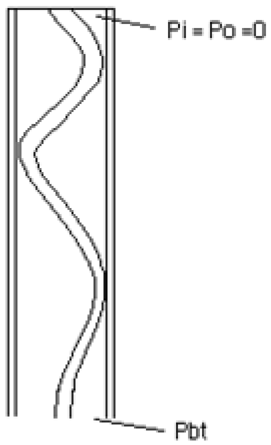


Figure 4. Tubing buckles because the density of the tubing is less than the liquid.

If the tubing were made of superlight material, just as an example w_s equals almost to zero, at the top of the tubing where the inside and outside pressures are zero, the real force would almost be the same as at the bottom. Thus, the fictitious force would be compressive and the whole tubing would be buckled. At the bottom the tubing would be straight, but moving upwards the degree of buckling would increase as shown in Figure 4. A tubing closed at the bottom may top buckle if the displaced fluid outside of the tubing is heavier than the steel and the fluid inside the tubing combined [4].

2.2 Calculating the length changes of the tubing

Different types of packers are used today such as the mechanic, hydraulic and hydrostatic set packers. They can be equipped with a polished bore receptacle (PBR) or an integral packer. A PBR allows the tubing to move freely up- and downwards after the packer is set. An integral packer does not allow the tubing to move.

2.2.1 Packer permitting free motion

There are five types of length changes related to packer force:

ΔL_1, length change caused by the piston force

ΔL_2, length change caused by helical buckling

ΔL_3, length change caused by ballooning of the tubing

ΔL_4, length change caused by change of temperature

ΔL_5, length change caused by the slack off force (discussed later)

ΔL_1 is the length change caused by the piston force. Comparing the tubing to a metal rod, we know from elementary mechanics that the rod will shorten or elongate when applying a compressive or tension force at the ends. The tubing can be elongated if the pressure below the tubing is reduced, or it could shorten it if the pressure is increased.

$$\Delta L_1 = \frac{L\Delta F}{EA_s} \qquad 2.12$$

The change in piston forces, ΔF, determines whether the tubing shortens or elongates:

$$\Delta F = P_{i2}A_i - P_{i1}A_i - \left(P_{bt2}A_p - P_{bt1}A_p\right) \quad (for\ plugged\ tubing) \qquad 2.13$$

$$= P_{i2}A_i - P_{i1}A_i - P_{i2}A_p + P_{i1}A_p \quad \left(for\ open\ tubing, P_{bt} = P_i\ and\ here\ A_p = A_o\right) \qquad 2.14$$

$$= P_{i1}(A_o - A_i) - P_{i2}\,(A_o - A_i) \quad (for\ open\ tubing) \qquad 2.15$$

$$= P_{i1}A_s - P_{i2}A_s \quad (for\ open\ tubing) \qquad 2.16$$

In our cases the area of the packer bore is the same as the outer area of the tubing.

ΔL_2 is the length change caused by helical buckling below the neutral point as can be seen in Figure 2. Because ΔL_2 governs length change due to buckling one must use the fictitious force at the packer depth. For a vertical well:

$$\Delta L_2 = -\frac{{R_c}^2\Delta F_f^2}{8EIw} \qquad 2.17$$

Note that ΔL_2 only exists if the string is buckled. Thus, if ΔF_f is positive (tension) ΔL_2 is zero. The fictitious force at the packer depth can be expressed as:

$$F_f = -\mathrm{P_{bt}A_s} + \mathrm{w_s} * \mathrm{L} + P_o A_o - P_i A_i \quad 2.18$$

$$= -P_i(A_o - A_i) + 0 + P_o A_o - P_i A_i \quad 2.19$$

$$= P_i A_i - P_i A_o + P_o A_o - P_i A_i \quad 2.20$$

$$= -P_i A_o + P_o A_o\,, \qquad in\ our\ case\ \ A_o = A_p \quad 2.21$$

$$= A_p(P_o - P_i) \quad 2.22$$

In actual problems almost always $P_i = P_o$ at initial condition and the fictitious force at initial condition is zero. Thus, it is the change in fictitious force that makes the tubing buckle:

$$\Delta F_f = A_p(\Delta P_o - \Delta P_i) \quad 2.23$$

ΔL_3 is the length change caused by ballooning of the tubing caused by flow inside the tubing and change in radial pressure forces. Consider the tubing filled with liquid in static conditions, and later replaced by another liquid in either static condition or in motion. The liquid flow result in a pressure drop modifying the radial pressure forces and imparts a force to the tubing wall. Both effects change the length of the tubing. Similarly the length can also be changed by changing the fluid pressure in the annulus and thus the radial pressure forces. The length change caused by ballooning is given by:

$$\Delta L_3 = -\frac{v}{E}\frac{\Delta\rho_i - R^2\Delta\rho_o - \frac{1+2v}{2v}\delta}{R^2 - 1}L^2 - \frac{2v}{E}\frac{\Delta P_i - R^2\Delta P_o}{R^2 - 1}L \quad 2.24$$

δ is the pressure drop per unit length due to flow in the tubing. δ is positive when the flow is downward and zero in case of no flow.

ΔL_4 is the length change caused by change of temperature and is given by:

$$\Delta L_4 = L\beta\Delta t \quad 2.25$$

β is the coefficient of thermal expansion [3].

2.2.2 Packer permitting limited motion

ΔL_5 is the length change caused by the slack off force. Consider a packer which permits limited motion as shown in Figure 5.

When the tubing has landed further slack off at the surface sets the tubing just above the packer to a compression. In order to calculate the total length change after the pressure and temperature is changed, one must know the length change the tubing would have after slack off and before pressure and temperature change when the packer restrain is removed and the tubing is allowed free motion. The imaginary elongation is called ΔL_5. The slack off is normally given in weight and not length. Thus, ΔL_5 is given by:

$$\Delta L_5 = \frac{LF}{EA_s} + \frac{R_c^2 F^2}{8EIw} \qquad 2.26$$

, which is the same as the sum of ΔL_1 and ΔL_2, but the force used in the equation is the slack off force. The equation describes the length change that the piston and helical buckling effect would have in order to push a non restricted tubing back to the original position at where the tubing landed. When the packer restraint is removed the tubing elongates. ΔL_5 is this elongation. The total length change of the tubing is naturally the sum of all length changes:

$$\Delta L = \Delta L_1 + \Delta L_2 + \Delta L_3 + \Delta L_4 + \Delta L_5 \qquad 2.27$$

Note that in case of a packer permitting limited motion the elongation ΔL cannot be positive as the packer doesn't permit an elongation. In that case the answer is zero. On the other hand a shortening (negative ΔL) is a real answer.

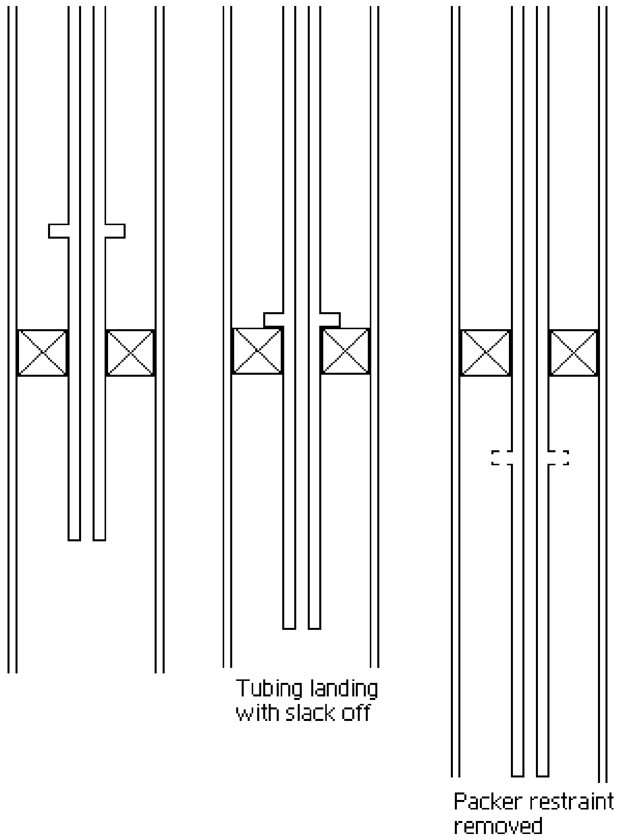
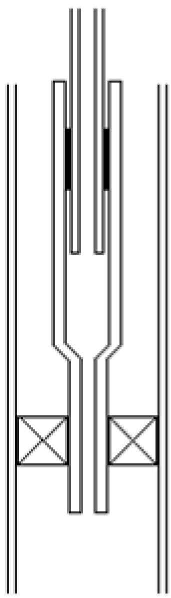


Figure 5. Packer permitting limited motion, (landing of tubing, slack off and packer restrain removed).

If the length change is longer than the seals the annulus is allowed to communicate with the tubing. This is not a wanted situation where the primary barrier has failed and a work-over needs to be done and it could result in costly operations [3].



2.2.3 Packer with PBR

A packer with PBR permits free motion of the tubing, as shown in Figure 6. The seal between the PBR and the tubing allows the tubing to move frictionless up and down without any fluid communication with the annulus. A PBR does not allow slack off and therefore ΔL_5 is zero [3]. Using a PBR A_p is the inner diameter of the PBR.

2.2.4 Integral packer

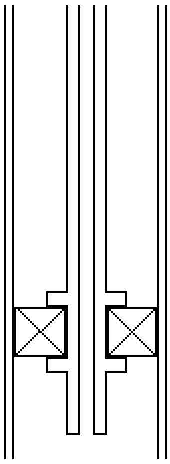


Figure 7. Packer permitting no motion.

Consider a packer permitting no motion in either direction as shown in Figure 7. The tubing is now fixed in two ends and it can neither move up- nor downwards. In other words, ΔL has to be equal to zero. Since the tubing is not allowed to move the piston effect cannot shorten or elongate the tubing, but the piston force will instead be acting on the packer. Imagine that the tubing were allowed to move freely and buckled as a result of pressure change, there would be a shortening caused by helical buckling and ballooning. The packer does not allow the tubing to move and therefore the tubing must be stretched the same length as it was shortened. If change in temperature elongates the tubing the tubing has to be shortened the same length. All the length changes have to equal the length change needed to place the tubing back to the packer depth [3]:

$$\Delta L = \Delta L_1 + \Delta L_2 + \Delta L_3 + \Delta L_4 + \Delta L_5 = 0 \qquad 2.28$$

$$\Delta L_1 = -\Delta L_2 - \Delta L_3 - \Delta L_4 - \Delta L_5 \qquad 2.29$$

Notice that ΔL_1 in equation 2.29 is different from ΔL_1 in equation 2.12 and is only valid for a packer permitting no motion.

2.3 The packer body force

The objective of the packer is to seal the annulus as shown in Figure 8. If the pressures on each side of the packer body are different, there will be a net force working on the packer body. The packer body force is expressed by:

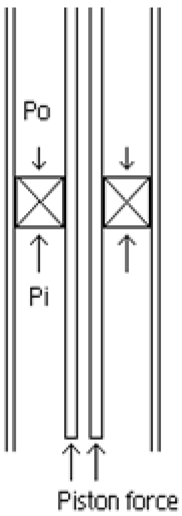


Figure 8. Packer body force.

$$F_{pb} = P_i A_{pb} - P_o A_{pb} \qquad 2.30$$

$$F_{pb} = P_i\left(A_w - A_p\right) - P_o\left(A_w - A_p\right) \qquad 2.31$$

$$F_{pb} = A_a(P_i - P_o) \qquad 2.32$$

The pressure differences can for instance be caused by pressure testing of the annulus, pressure testing of the tubing, production, any kind of injection or any changes in the densities in the annulus or the tubing. During a pressure test of the tubing the packer body is:

$$F_{pb} = A_a * (\Delta P_i - \Delta P_o) \qquad 2.33$$

Chapter 3: Integral packers in vertical wells

3.1 Length of buckled section in a vertical well

To find the buckled length of the tubing one has to find the gradient of the fictitious force, that is how much the fictitious force changes per unit length:

$$\mathrm{F_{fz}} = \frac{\mathrm{F_{fp}} - \mathrm{F_f}}{\mathrm{TVD_p} - \mathrm{TVD}} \qquad 3.1$$

Where F_{fp} is the fictitious force just abouve the packer, F_f is the fictitious force at a randomly chosen point of TVD above the packer and TVD_p is the true vertical depth at the packer. The buckled length can then be found by:

$$LB_v = \frac{\mathrm{F_{fp}} - \mathrm{BL}}{\mathrm{F_{fz}}} \qquad 3.2$$

Where LB_v is the buckled length of the tubing in the vertical section and BL is the buckling limit. WellCat uses zero lbs as buckling limit for vertical sections. However, Wu and Juvkam-Vold [5] used an energy analysis to predict helical buckling in vertical wells and concluded that the helical buckling limit for a straight vertical well is not zero. They derived an expression for the helical buckling limit for a vertical section:

$$BL = -5{,}55(EIw^2)^{1/3} \qquad 3.3$$

For the tubing and fluid density used in this thesis the buckling limit is – 7 000 lbs.

3.2 Vertical well, mechanical set packer and pressure test of tubing (case 1)

The tubing is lowered into the well until the setting depth is reached. The packer is set mechanically, meaning that there will be no change of pressures neither on the inside nor outside of the tubing. The packer seals off the annulus so that the pressure test of the tubing only increases the pressure inside the tubing and below it. The tubing is fixed at the bottom at the packer and at the top at the tubing hanger. Imagine that the tubing were allowed to move freely up or down during the pressure test of the tubing. The piston force acting on the steel area, the helical buckling and the ballooning effect would shorten the tubing. However, in our case the tubing at packer depth is fixed, which means that the tubing is not allowed to shorten and thus the shortening caused by the helical buckling and ballooning effect must equal to the elongation required to stretch the tubing back to the original position. The tubing to packer force is the sum of two forces, the pressure area force acting on the steel area in the upward direction and the force related to Hooke's law, that is the force required to stretch the tubing the same length as the tubing should be shortened if it were hanging freely at the bottom. Both forces work in the upward direction and the packer force becomes:

$$F_{t2p} = \Delta F_P + F_h \tag{3.4}$$

$$= A_s * \Delta P_i + \frac{\Delta L_1 E A_s}{L_t} \tag{3.5}$$

Where:

$$\Delta L_1 = -\Delta L_2 - \Delta L_3 \tag{3.6}$$

Because the pressure on the bottom of the packer body is greater than the pressure on the top there will be a net force on the packer body acting upwards.

$$F_{pb} = A_a * (\Delta P_i - \Delta P_o) \tag{3.7}$$

The force that the packer transfers to the casing is the sum of the force that the tubing transfers to the packer and the packer body force:

$$F_{p2c} = F_{t2p} + F_{pb} \tag{3.8}$$

$$= A_s * \Delta P_i + \frac{\Delta L_1 E A_s}{L_t} + A_a * (\Delta P_i - \Delta P_o) \tag{3.9}$$

An example of a theoretical field case is presented in Appendix A as case 1 using the equations and principles above.

3.3 Vertical well, hydraulic set packer and pressure test of tubing (case 2)

Case 1 and 2 are similar. The same casing and tubing are used, but the packer is a hydraulic set packer. The principle of setting the packer is illustrated in Figure 9. The tubing is plugged at the bottom. At stage 1 in Figure 9 the tubing is hanging freely and the inside and outside pressure is the same. At stage 2 in Figure 9 the pump at the surface pressurizes the inside of the tubing and the packer is set when the pressure inside the tubing at packer depth reaches a predetermined differential to the outside pressure. In this calculation example the pressure differential that activates the packer is 3 000 psi, that is the inside pressure has to be 3 000 psi higher than the outside pressure. The fictitious force in this condition is:

$$Ff(z) = F_R(z) + A_o P_o(z) - A_i P_i(z) \qquad 3.10$$

$$Ff(0) = A_i P_i - A_o P_o + A_o P_o - A_i P_i = 0 \qquad 3.11$$

In this state the fictitious force is zero and the tubing will not buckle. However, the pressure force of the 3 000 psi on the inside of the tubing working at the area of the plug on the bottom of the tubing elongates the tubing, while the ballooning effect shortens it. The total length change shows that the tubing elongates. In fact, with the input parameters used in the theoretical cases, the tubing will elongate whatever the inside radius and pump pressure may be. The elongation during the setting of the packer is:

$$\Delta L = \Delta L_1 + \Delta L_3 \qquad 3.12$$

$$= \frac{L * \Delta F}{E * A_s} - \frac{v}{E}\frac{\Delta\rho_i - R^2\Delta\rho_o - \frac{1+2v}{2v}\delta}{R^2-1}L^2 - \frac{2v}{E}\frac{\Delta P_i - R^2\Delta P_o}{R^2-1}L \qquad 3.13$$

$$= \frac{L * \left((P_{i2}A_i - P_{i1}A_i) - (P_{bt2}A_o - P_{bt1}A_o)\right)}{E * A_s} - \frac{2v}{E}\frac{\Delta P_i - R^2\Delta P_o}{R^2-1}L \qquad 3.14$$

Equation 3.14 assumes no flow in the tubing and no change in the densities.

At stage 3 in Figure 9 the packer is set and the pump is turned off leaving the tubing in tension (the inside and outside pressures are the same). The tubing to packer force is simply the Hooke's force required to elongate the tubing the same length as the total length change during the setting of the packer:

$$\mathrm{F_{t2p}} = \mathrm{F_h} = \frac{\Delta \mathrm{LEA_s}}{\mathrm{L_t}} \qquad 3.15$$

where L_t is the length of the tubing from the tubing hanger to the packer. At this stage the pressure in the annulus and below the tubing is the same and the packer body force is zero. The plug at the end of the tubing is removed and the pressures inside and below the tubing are the same.

At stage 4 in Figure 9 the pumps are turned on for the pressure testing of the tubing and the pressure inside the tubing increases by 3 000 psi. Imagine a freely hanging tubing. The ballooning effect shortens the tubing. Stretching the tubing back at the packer position elongates the tubing. In other words, because the tubing is fixed in both ends (at the tubing hanger and at the packer) the ballooning effect stretches the tubing, thus the positive (+) sign in the ballooning effect at stage 4 and 5. Similarly the helical buckling effect stretches the tubing at stage 5. The size of the ballooning effect is still the same at stage 4 as during the setting of the packer (stage2). The tension force that the bottom plug provided at the setting of the packer is now provided by the packer. Thus, the condition of the tubing is similar to the setting of the packer and the tubing does not buckle.

At stage 5 the pumps pressurize the tubing further to 9 993 psi above the initial pressure. The ballooning effect and the helical buckling stretch the tubing further. The tubing buckles because the fictitious force is less than the BL. The available pressure for the buckling is therefore 6 993 Psi. The ballooning effect is as always found by equation 2.24.

There are two ways of determining the helical buckling length change for a hydraulic set packer. One can use the helical buckling length change equation determined in case 1, which is the equation of the trend line in Figure A.4 in Appendix B:

$$\Delta L_2 = -9{,}87096 * 10^{-10} * P_p^2 \; + \; 2{,}14436 * 10^{-7} * P_p \; + \; 2{,}38095 * 10^{-4} \qquad 3.16$$

where P_p is the pump pressure in psi and ΔL_2 is in ft. This equation is only valid for the same tubing and mud weight as presented in this thesis. The equation is the trend line equation of the helical buckling length change curve and is plotted against the pump pressure.

Another way of finding ΔL_2 is to calculate ΔL_2 for a similar case with a mechanical set packer when the pressure test of the tubing is 6 993 psi. The difference between these two methods of finding ΔL_2 is very small, in fact only 23 lbs in the final result for the tubing to packer force in our case, so both methods are acceptable to use. In the calculation of the results a mechanical set packer was used to find ΔL_2.

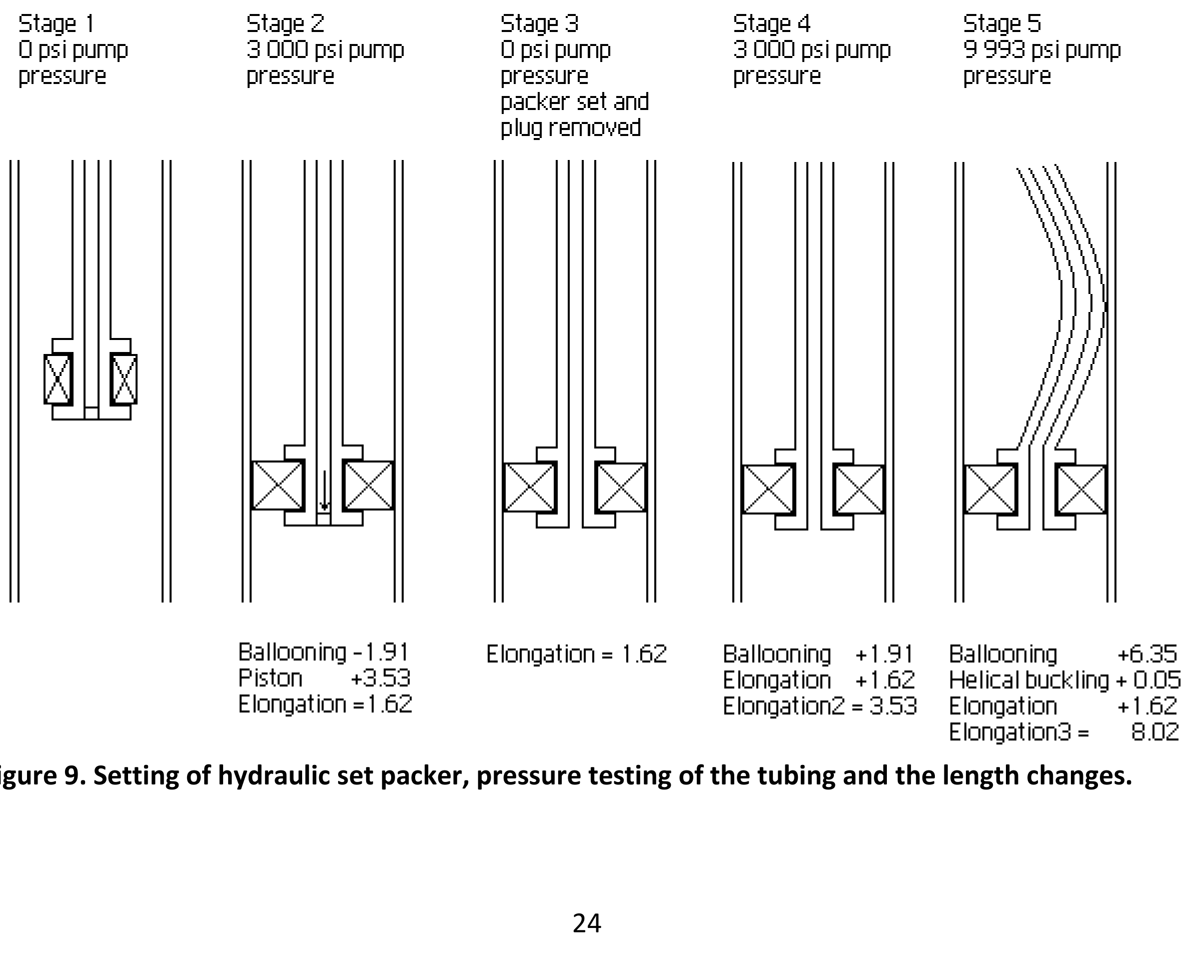


Figure 9. Setting of hydraulic set packer, pressure testing of the tubing and the length changes.

When the pump pressure is 9 993 psi, there must be an increase in piston force acting on the steel area at the bottom of the tubing as described in eq. 2.7. The tubing to packer force consists of the piston force and the Hooke's force (the force required to stretch the tubing the same length as it would shorten if the packer were allowed to slide frictionless up the casing wall). Thus the tubing to packer force becomes:

$$F_{t2p} = \Delta F_p + F_h \qquad 3.17$$

$$F_{t2p} = A_s \Delta P_i + \frac{\Delta \mathrm{LEA_s}}{\mathrm{L_t}} \qquad 3.18$$

where ΔL is the total elongation at stage 5 (8,02 ft for the theoretical field case in Appendix B). This is the simplest method of calculating the tubing to packer force.

However, another procedure could be used to calculate the tubing to packer force using the tubing to packer force calculated in equation 3.15. The piston force is then as described in equation 2.7 but now the tubing only shortens by the ballooning effect (eq.2.24) and the helical buckling effect (eq.3.16). Using this method one has to keep in mind that in the calculation of the ballooning effect 9 993 psi should be used and for the helical buckling 6 993 psi. The equation for the tubing to packer force is then:

$$F_{t2p} = F_{t2p\,old} + \Delta F_p + F_h \qquad 3.19$$

Where $F_{t2p\ old}$ represents the tubing to packer force after the packer is set and the pressure is at initial condition (stage 3) as described in equation 3.15.

An example of a theoretical field case is presented in Appendix B as case 2 using the equations and principles above. The elongations in Figure 9 referes to case 2 in Appendix B.

3.4 Hydrostatic set packer

Fields that require high angle and extended reach wells could put completion packers beyond wireline access. Using coiled tubing (CT) to set and pull plugs during the completion installation is expensive and time consuming. Absolute well pressure activation is a system where the tool holds an atmospheric pressure chamber and uses a rupture disk for actuation. When the well pressure exceeds the actuation pressure the rupture disk ruptures and wellbore fluid flows into the tool. The driving force for setting the packer is the pressure difference between the atmospheric chamber and the wellbore fluid. The packer is cost-effective in cases where it can remove the need for CT intervention. A drawback by using hydrostatic set packer is that the well has to be unperforated or the lower completion has to be hydraulically isolated [6]. Modelling of packer forces for hydrostatic set packers is easily taken care of using the theory presented in the present work. Design equations for this application are not developed as a part of this work.

Chapter 4: Deviated wells without friction

4.1 The equivalent height concept

Aadnøy et al. [7] (1999) published the equivalent height concept to calculate the weight of a pipe in a deviated well.

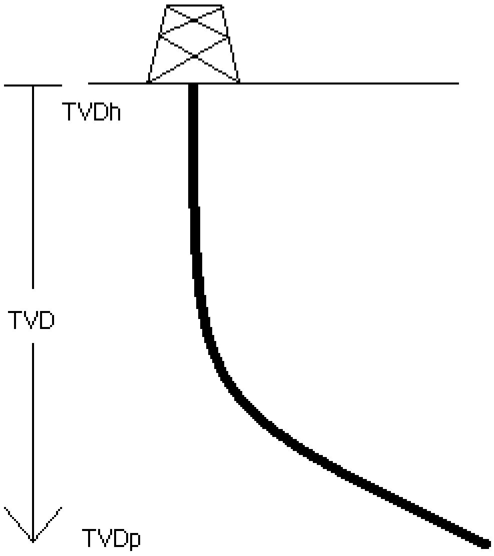


Figure 10. Deviated well with a sail section.

The equivalent height concept says that weight of a frictionless string inside the deviated well at the tubing hanger in the figure is [7]:

$$F_{ah} = w * (TVD_p - TVD_h) \qquad 4.1$$

At any given point in an open string (without packer forces) the axial force is:

$$F_R = -A_s * P_{bt} + w_s * (TVD_p - TVD) \qquad 4.2$$

These two expressions are valid for a frictionless well.

4.2 Length of buckled tubing in a sail section

To find the buckled length of the tubing in a sail section one has to find the gradient of the fictitious force in the sail section:

$$\mathrm{F_{fs}} = \frac{\mathrm{F_{fp}} - \mathrm{F_f}}{\mathrm{MD_p} - \mathrm{MD}} \qquad 4.3$$

Where the F_{fp} is the fictitious force just above the packer, F_f is the fictitious force at a randomly chosen point of MD above the packer in the sail section and MD_p is the MD at the packer. The buckled length can then be found by:

$$LB_s = \frac{\mathrm{F_{fp}} - \mathrm{BL}}{\mathrm{F_{fs}}} \qquad 4.4$$

where LB_s is the length of the buckled tubing in the sail section and BL is the buckling limit. There are many buckling limits derived by researchers. Aasen and Aadnøy (2002) [8] summarized buckling models that were available at that time. For curved and inclined wells, the general buckling limit is:

$$F_H = \frac{\gamma_1}{4\mathrm{A}}\left[1 + \sqrt{1 + \frac{4AB\ sin\alpha}{\gamma_2}}\right] \qquad 4.5$$

$$= \frac{\gamma_1 EI}{R_c r}\left[1 + \sqrt{1 + \frac{R_c r^2 w_{bp}\ sin\alpha}{\gamma_2 EI}}\right] \qquad 4.6$$

where A and B are given by:

$$A = \frac{\mathrm{R_c r}}{\mathrm{4EI}} \qquad 4.7$$

$$B = w_{bp} r \qquad 4.8$$

The buckling limit for a straight inclined well is:

$$\lim_{r\to\infty} F_H = \frac{\gamma_1}{\gamma_2}\sqrt{\gamma_2}\sqrt{\frac{w_{bp} EI \sin\alpha}{R_c}} \qquad 4.9$$

$$= \gamma_3 \sqrt{\frac{w_{bp} EI \sin\alpha}{R_c}} \qquad 4.10$$

Reference	γ_1	γ_2	γ_3
Chen/Lin/Cheatham, 1990[9]			-2,83
He/Kyllingstad, 1995[10]			-2,83
Lubinski/Woods, 1953[11]			-2,85
Lubinski/Althouse/Logan, 1962[3]			-2,4
Qui/Miska/Volk, 1998[12]	-8	2	-5,66
Qui/Miska/Volk, 1998[13]	-7,04	3,52	-3,75
Wu/Juvkam-Wold, 1993[14]			-3,66
Wu/Juvkam-Wold, 1995[15]	-12	8	-4,24

Table 1. Buckling coefficients at helical buckling [8].

To find the BL used by WellCat different buckling models were used in equation 4.4 (above) and buckled length compared to WellCat. None of the above limits in Table 1 met the buckled length calculated by WellCat. However, the Dawson and Paslay [16] (1984) snaking buckling limit equation for a straight inclined section was found to give the same buckled length as WellCat:

$$BL = -2\sqrt{\frac{EIw_{bp}\sin\alpha}{R_c}} \tag{4.11}$$

By using the Dawson and Paslay equation, the buckling calculations performed by WellCat are conservative.

4.3 Buckling length change for a sail section

The Lubinski [3] equation for helical buckling length change is only valid for vertical wells. A couple of methods [17, 18] were used in an attempt to get the same ΔL_2 result as WellCat, but without success. Mitchell [2] (2006) published an equation that governs length change (ΔL_2) due to lateral buckling in a sail section:

$$\Delta L_{2sl} = -\frac{R_c^2}{4EIw_{bp}\cos\alpha}\left(F_{fp} - BL\right)\left[0.3771 * F_{fp} - 0.3668 * BL\right] \tag{4.12}$$

Mitchell [2] modified slightly the familiar Lubinski [3] equation (2.17) for ΔL_2 for helical buckling by:

$$\Delta L_{2sh} = -\frac{R_c^2}{8EIw_{bp}\cos\alpha}\left[F_{fts}^2 - F_{fp}^2\right] \tag{4.13}$$

where F_{fts} is the fictitious force at the top of the sail section. Since ΔL_2 at first is not known and the fictitious force above the packer depends on the axial force and thus the tubing to packer force, one has to assume that ΔL_2 zero. When the fictitious force above the packer is calculated the real ΔL_2 can be found. This value of ΔL_2 should then be used to calculate the tubing to packer force, axial force and fictitious force. This process of using an old ΔL_2 to calculate a new one should be repeated a couple of times until the whole number to the third decimal place have converged.

WellCat uses the following criteria for buckling [19]:

$F_f < F_{Paslay}$ → No buckling

$\mathrm{F_{Paslay}} < F_{\mathrm{f}} < 2{,}7 * \mathrm{F_{Paslay}}$ → Lateral buckling

$2{,}7\mathrm{F_{Paslay}} < \mathrm{F_f} < 2{,}83 * \mathrm{F_{Paslay}}$ → Linear interpolation between lateral and helical buckling

$\mathrm{F_f} > 2{,}83 * \mathrm{F_{Paslay}}$ → Helical buckling

In order to calculate the correct ΔL_2 of the tubing, one need to consider that the tubing can be helically buckled, laterally buckled and in a transition phase between helically and laterally buckled. The size of F_{fp} determines the buckling condition of the tubing. As stated earlier WellCat uses the Dawson and Paslay BL (eq. 4.11) and then the tubing in a vertical well can only be helically buckled. WellCat uses the Lubinski et al. [3] equation (eq.2.17) to calculate ΔL_2 for a vertical well. If the forces are not too high an increase of sail angle will decrease the helically buckled fraction of the tubing and the laterally buckled fraction will increase. At some sail angle the tubing will only experience the transition phase and lateral buckling. Increasing the sail angle a little bit more will make the transition phase disappear and only lateral buckling occurs.

In order to find the fraction of the type of buckling of the buckled length section, one needs to find the available buckling force for each type of buckling. Is F_{fp} in the lateral, transition or the helical buckled section? If F_{fp} is in the lateral buckled section, there will be no transition phase or helical buckled section. If F_{fp} is in the transition section there will not be a helical buckled section.

If F_{fp} is in the helically buckled section the available force for helical buckling is given by:

$$F_{ahel} = F_{fp} - 2{,}83 * F_{Paslay} \tag{4.14}$$

the available force for the transition buckling is:

$$F_{atra} = (2{,}83 - 2{,}7) * F_{Paslay} = 0{,}13 * F_{Paslay} \tag{4.15}$$

and the available force for the lateral buckling is:

$$F_{alat} = 2{,}7 * F_{Paslay} - F_{Paslay} = 1{,}7 * F_{Paslay} \tag{4.16}$$

The buckled length of the different types of buckling can be expressed by:

$$LB_i = \frac{F_i}{F_{fs}} \quad ,\mathrm{i} = 1{,}2{,}3 \tag{4.17}$$

where i denotes the type of buckling and i=1=lateral, 2= transition and 3 = helical. The total buckled length is expressed by:

$$LB_t = \sum_{i=1}^{n} LB_i \tag{4.18}$$

The length fractions of the different type of buckling are given by:

$$S_i = \frac{LB_i}{LB_t} \qquad , i = 1,2,3 \tag{4.19}$$

Finally the total ΔL_2 for the condition where F_{fp} is in the helical buckled section can be found:

$$\Delta L_2 = S_1 * \Delta L_{2sl} + S_2 * \frac{(\Delta L_{2sl} + \Delta L_{2sh})}{2} + S_3 * \Delta L_{2sh} \tag{4.20}$$

If F_{fp} is in the transition section there is no helical buckling and equation 4.14 should therefore not be used. Linear interpolation between lateral and helical buckling will give a good approximation of ΔL_2 for the transition section:

$$\Delta L_{2tra} = \left(1 - \frac{F_{fp} - 2{,}7 * F_{Paslay}}{2{,}83 * F_{Paslay} - 2{,}7 * F_{Paslay}}\right) * \Delta L_{2sl} + \frac{F_{fp} - 2{,}7 * F_{Paslay}}{2{,}83 * F_{Paslay} - 2{,}7 * F_{Paslay}} * \Delta L_{2sh} \tag{4.21}$$

And the total ΔL_2 for the condition where F_{fp} is in the transition section can be found:

$$\Delta L_2 = \Delta L_{2tra} + S_1 * \Delta L_{2sl} \tag{4.22}$$

If F_{fp} is in the lateral section then ΔL_2 is expressed with eq. 4.12.

When ΔL_2 is found a new tubing to packer force, axial and fictitious force must be calculated. Then a new ΔL_2 must be calculated. This cycle should be repeated until ΔL_2 converges.

4.4 Mechanical set packer in a deviated well and pressure test of tubing (case 3)

The concept for mechanic set packer in a sail section is similar to a vertical well, only implementing the equations described so far in chapter 4. The deviated wells in case 3 and 4 are assumed to be frictionless. The wells are vertical to the kick off point (KOP) at 1500 ft. The dog leg severity (DLS) in the build up section (BU) is 3degrees/100 ft. The sail section starts when the well is 60 degrees from vertical. The packer is set at 16 974 ft MD. The calculated results can be seen in Appendix C.

4.5 Hydraulic set packer in a deviated well and pressure testing of tubing (case 4)

Case 4 has the same well path as case 3. The concept for hydraulic set packer in a sail section is similar to a vertical well with hydraulic set packer, only implementing the theory discussed so far in chapter 4. The packer is set hydraulic at 500 psi and the pressure test of the tubing is performed at 9 993 psi. If the packer was set at 3 000 psi there would be no buckling. Thus, 500 psi was chosen as the setting pressure to get some buckling. The calculated results can be seen in Appendix D.

4.6 The effect of hole angle on the ΔL_1, ΔL_2, ΔL_3 and buckled length

Figure 11, 12, 13, 14 and 15 are based on a mechanical set packer placed at the same MD as in case 3 and 4. The pressure gradient is the same as WellCat and the pressure test of the tubing is 9 993 psi. The KOP is at 1500 ft as before. For simplicity the sail section starts at 1600 ft even though it's unrealistic to have such DLS for high angles. However, since the well is frictionless it does not matter. The angle of the sail section is the only thing that varies in the analysis outlined below.

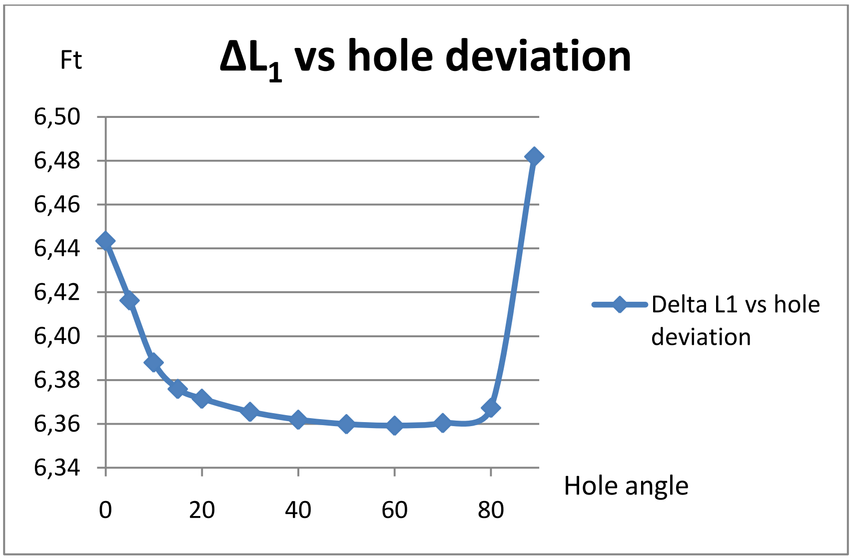


Figure 11. Effect of sail angle on ΔL_1.

Figure 11 shows length change caused by the Hooke's force (the force needed to stretch the tubing back to the packer position). The shape of the curve in Figure 11 is a direct result of ΔL_1 being dependent of ΔL_2 and ΔL_3.

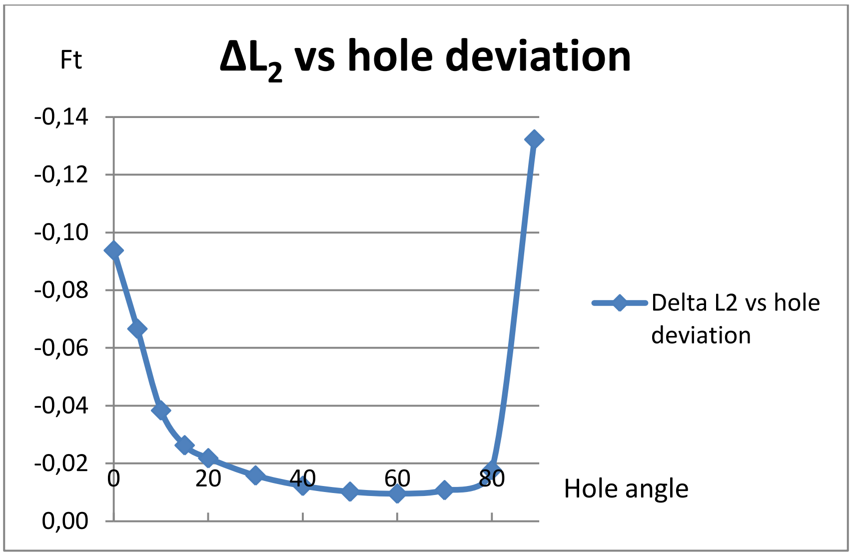


Figure 12. Effect of sail angle on ΔL_2.

Figure 12 shows that ΔL_2 is getting smaller as the sail angle increases. In a vertical well the buckling is helical. Helical buckling gives a larger ΔL_2 than lateral buckling. When the sail angle is increased the portion of helical buckling is gradually transformed to lateral buckling. At some angle the tubing will only be laterally buckled and ΔL_2 accordingly small. This is the main reason why ΔL_2 drops so fast at small angles. ΔL_2 increases rapidly when the well gets close to horizontal and is a result of the well being frictionless. The axial force is nearly constant in the sail section when the sail section gets close to horizontal in a frictionless well. The inside and outside pressures will almost remain constant. Thus, the fictitious force will almost remain constant when the sail section gets close to horizontal and the buckled length increases rapidly as the sail angle approaches 90 degrees.

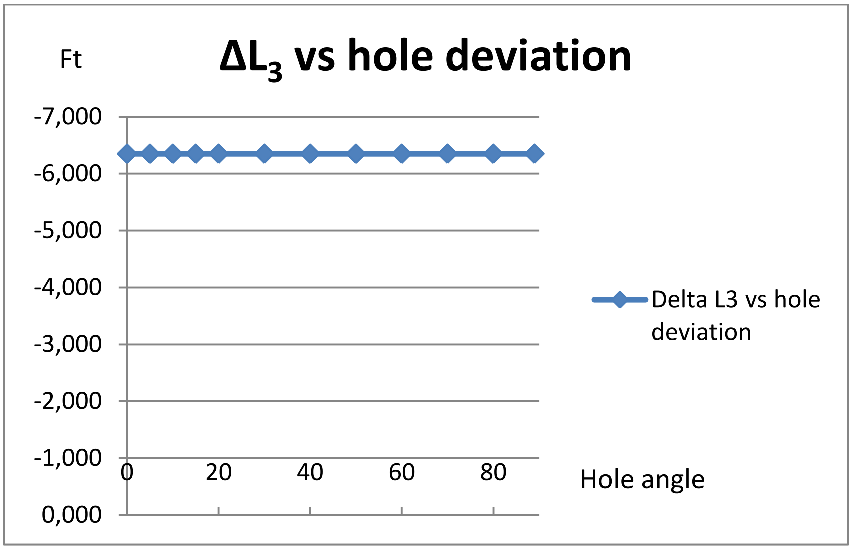


Figure 13. Effect of sail angle on ΔL_3.

Figure 13 shows that the ballooning effect does not depend on the hole angle.

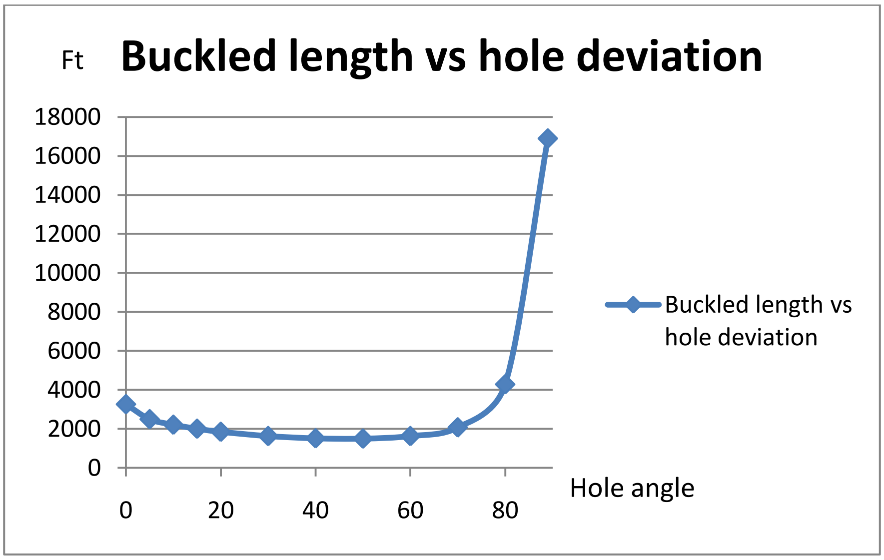


Figure 14. Effect of sail angle on total buckled length.

Figure 14 shows that increasing the sail angle, for small and medium angles, reduces the buckled length. This is a result of ΔL_1, which is a result of ΔL_2 and ΔL_3, and that the buckling limit goes into compression (less buckling interval for the fictitious force). Further the buckled length increases rapidly when the sail section gets close to horizontal. This is as discussed above a result of an almost constant fictitious force in the sail section.

4.7 Sensitivity of ΔL_1, ΔL_2, ΔL_3 and buckled length for small angles

A sensitivity analysis for small angles was conducted to study ΔL_1, ΔL_2, ΔL_3 and the total buckled length compared to the equations described in the thesis.

Sail Angle		0	1	2	3	4	5
ΔL_1	WellCat	6,45	6,43	6,44	6,43	6,43	6,42
	Excel	6,44	6,44	6,43	6,43	6,42	6,42
ΔL_2	WellCat	-0,09	**-0,07**	-0,08	-0,08	-0,07	-0,07
	Excel	-0,09	**-0,09**	-0,08	-0,08	-0,07	-0,07
ΔL_3	WellCat	-6,36	-6,36	-6,36	-6,36	-6,36	-6,36
	Excel	-6,35	-6,35	-6,35	-6,35	-6,35	-6,35
Buckled length	WellCat	3 258	**2 628**	2 766	2 658	2 498	2 494
	Excel	3 261	**2 908**	2 771	2 659	2 574	2 494
Buckling type in fractions	Lateral	0	0,2074	0,3078	0,3929	0,4696	0,5425
	Transition	0	0,0157	0,0233	0,0297	0,0355	0,0410
	Helical	1	0,7769	0,6689	0,5774	0,4949	0,4166

Table 2. WellCat vs. equations for small angles.

As the shaded cells show in Table 2 there seems to be some kind of instability in the WellCat output. The reason for the instability is unknown. It is unlikely to think that ΔL_2 decreases by 0,02 ft from vertical to 1 degree deviation and then increasing by 0,01 ft going from 1 to 2 degrees deviation and then decrease again from 3 to 4 degrees. The equations however seems to give a stable and more trustworthy result. The effect of the error on the total buckled length can be seen graphically in Figure 15. Table 2 shows that the tubing is only helically buckled in the vertical section. For small angles there will be a lateral, transition and helical buckled sections.

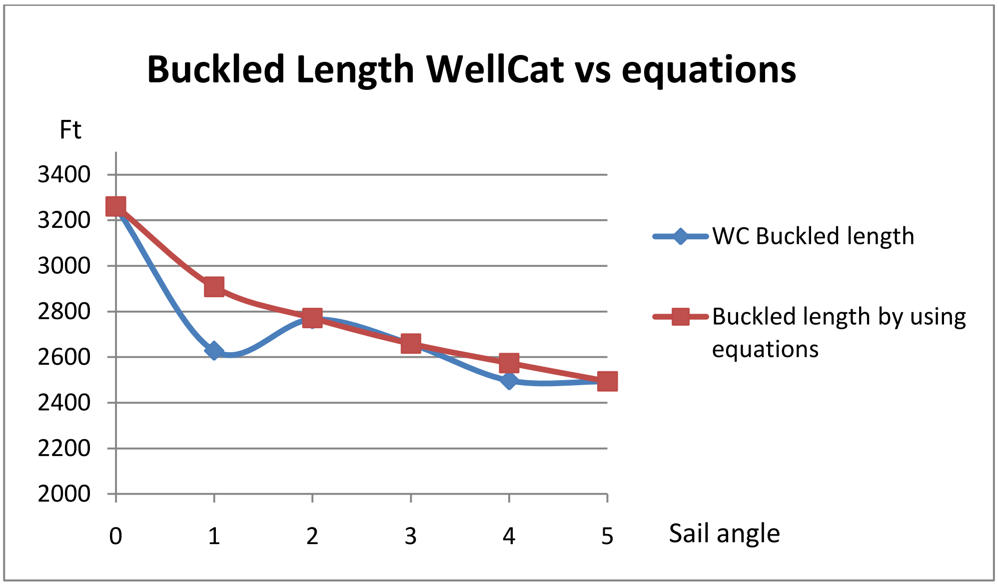


Figure 15. Comparing buckled length of WellCat and the equations.

Figure 15 clearly shows that the simulated buckling behavior by WellCat is unstable. However, in Figure 15 the WellCat buckled length is about 300 ft less than the excel calculations. The difference in this case is not really that significant keeping in mind that the buckling calculations are conservative in the first place by using the Dawson and Paslays BL. But one has to be aware that in other cases the simulator could give greater deviations. To be on the safe side one can always perform the buckling calculation by using the presented equations in Excel.

Chapter 5

Conclusion

Buckling of tubing has been studied in vertical and sail sections for frictionless strings for mechanic and hydraulic set packers. Equations used by the buckling simulator WellCat 2003.0.4.0 for these cases have been found.

Calculating the tubing to packer force is about finding the force needed to stretch a freely hanging tubing back to the packer position. One has to include that the tubing can buckle different ways in sail sections in the calculations.

WellCat is found to be conservative in the buckling calculations, using Dawson and Paslay [16] lateral buckling limit as initiation of buckling in the simulator software. It also uses the Dawson and Paslay buckling limit to calculate the length change due to lateral buckling in sail sections (ΔL_2) and the buckled length of the tubing. Going from a vertical well to a well with a sail section the buckled length is reduced because the buckling limit goes into compression and helical buckling transforms to lateral buckling as the hole angle increases. For a frictionless string the buckled length increases rapidly as the sail section approaches horizontal due to only small changes in the fictitious force in the horizontal section.

WellCat can in some cases be a bit unstable in the buckling calculations calculating “wrong” buckled length. The simulator is conservative and the practical significance of the deviation could be argued to be small. To be on the safe side one can perform the calculations by using the presented equations in Excel. The overall experience with the software is that it is reliable.

Recommendation to future work is to include friction in the buckling calculations. Also study the buckling calculations performed by WellCat in the BU and DO section.

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Appendix A

Results Case 1:

Input		
D_i	4,548	Inner diameter of the tubing, inches
D_o, inches	5,5	Outer diameter of the tubing, inches
D_w, inches	8,553	Diameter wellbore, inside casing string, inches
TVD and MD at Packer	16 974	Depth at packer depth, ft
TVD and MD end_o_t	16 975	Length TVD and MD at end of tubing, ft
TVD and MD wh	85	TVD and MD at the wellhead, ft
W_S	26	Tubing weight per unit length, lbs/ft
PPI1	7 933	Initial pressure inside tubing at packer depth, psi
PPI2	17 926	Final pressure inside tubing at packer depth, psi
PPO1, PPO2	7 936	Initial and final pressures outside tubing at packer depth, psi
ROI1, ROO1, ROI2, ROO2	0,4679	Densities inside and outside the tubing at initial and final condition, psi/ft
DPIS	9 993	Change of pressure inside tubing at surface, psi
v	0,27	Poisson's ratio
E	31 038 000	Young's modulus of elasticity, psi

Table 3. Input data used for the calculations in case 1.

The wellhead is located 85 feet below the RKB and should be thought of as a fixed point. The pressure data used in the calculations is taken from WellCat. The pressure gradient WellCat uses is not constant. It changes most likely because the compressibility of the fluid and the increase in temperature with depth is taken into account. Because there is a static situation and the tubing is not plugged, the initial inside and outside pressure should be the same at the packer depth and thus the wellhead pressures. WellCat calculates two different pressures at the same depth, which is impossible in the real world. The deviation is only 3 psi and does not have a significant impact on the parameters studied in the thesis. The 3 psi could be constructed by purpose in the input file. Poisson's ratio and Young's modulus of elasticity are taken from WellCat in order to get the same basis for the calculations performed in Excel.

Output	Excel	
A_W	57,455	Area off wellbore, inside of the casing string, inches^2
A_a	33,697	Area between the casing and tubing, inches^2
A_i	16,245	Area corresponding to tubing 4,542" ID, inches^2
A_O	23,758	Area corresponding to tubing 5,5"OD, inches^2
A_P	23,758	Area corresponding to packer bore 5,5" ID, inches^2
A_S	7,513	Cross-sectional area of tubing wall, inches^2
R	1,209	Ratio OD/ID of tubing, inches
R_C	1,527	Tubing to casing radial clearance, inches
I	23,916	Moment of inertia, inches^4
W_{bp}	1,874	Buoyed weight, tubing weight per inch, lbs/inch

Table 4. Areas, radial ratios, moment of inertia and buoyed weight of the tubing.

Table 4 is valid for all cases as the same tubing and casing is used in all cases and is therefore not repeated for the other cases.

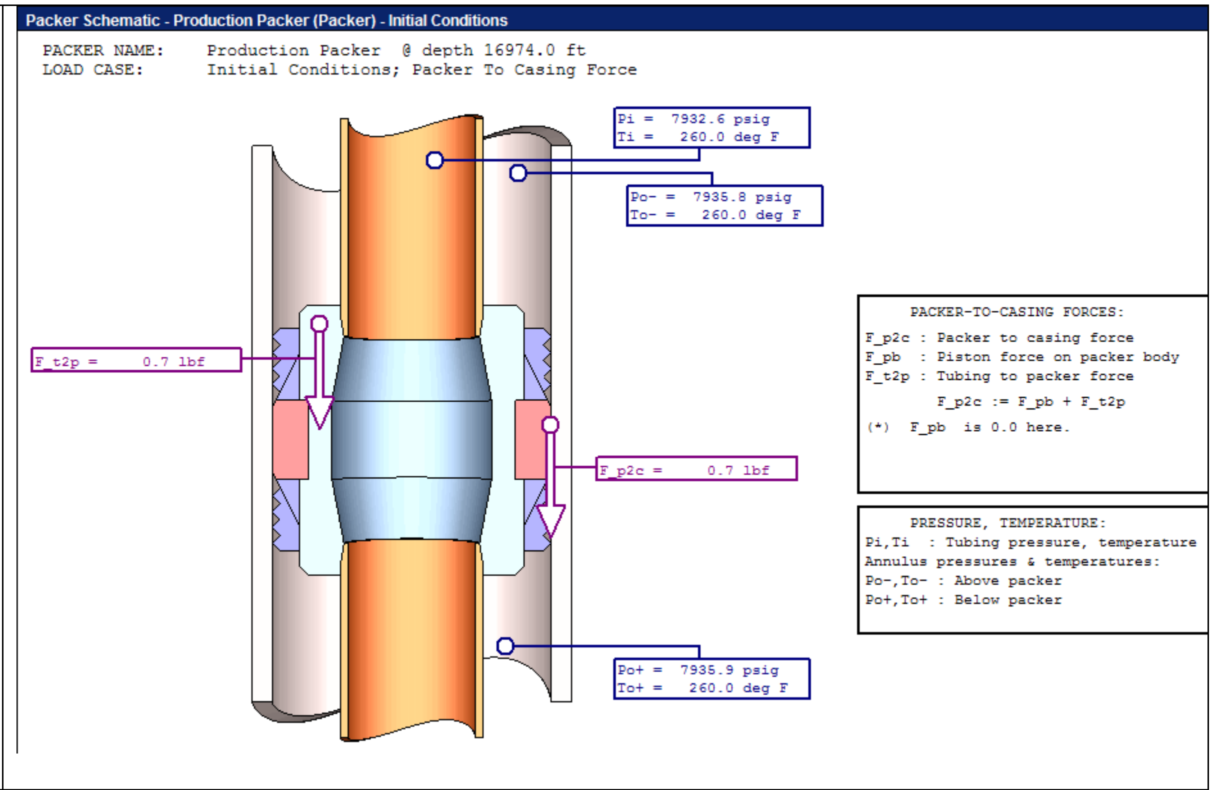
Calculations	Excel	
DPPI	9 993	Delta pressure inside tubing, psi
F_R	75 076	Force actual, delta piston force, lbs
F_h	89 048	Size of the Hooke's force to get the required length L1 , lbs
ΔL_1	6,45	Piston effect, Hooke's law, ft
ΔL_2	-0,10	Helical buckling, ft
ΔL_3	-6,35	Ballooning effect, ft

Table 5. Forces and length changes.

Output	Excel	
F_{pb}	336 629	Packer body force, delta pressure force in the annulus, lbs
F_{t2p}	164 124	Force tubing to packer, lbs
F_{p2c}	500 753	Force packer to casing, lbs
F_{ah}	468 598	Axial load at tubing hanger, lbs
F_R-	29 475	Axial load above packer, lbs
F_R+	-134 650	Axial load below packer, lbs

Table 6. Packer forces.

Initial condition



Pressure test of the tubing

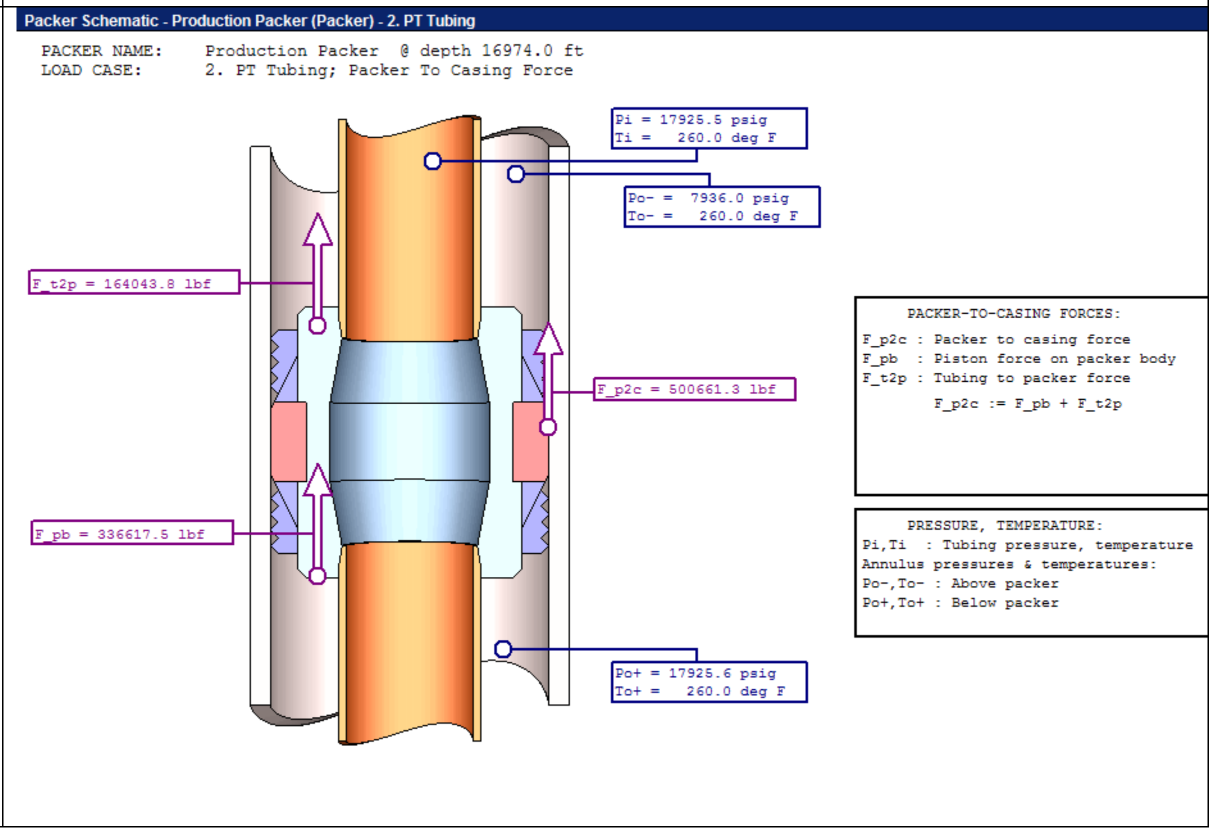
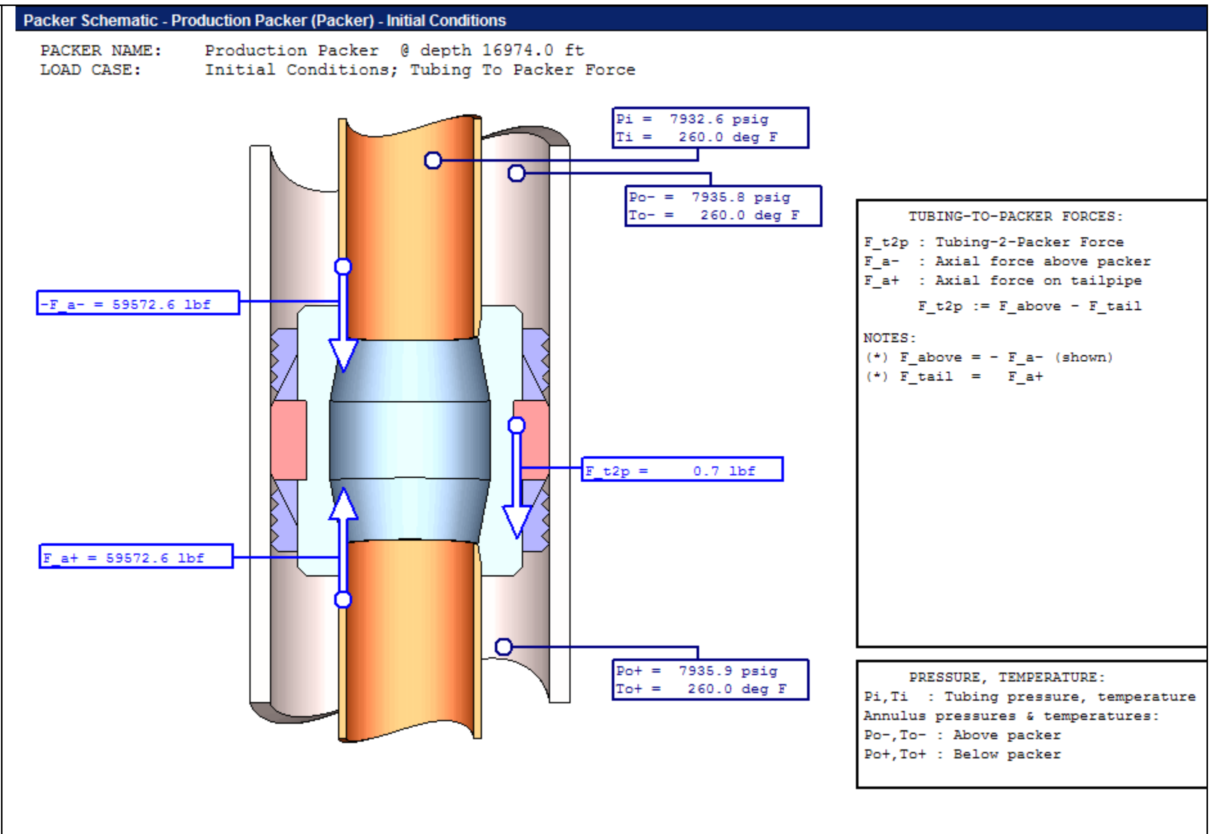


Figure A.1. WellCat illustration of the tubing to packer force, packer to casing force and packer body force at initial and final condition.

Figure A.1 shows the forces calculated by WellCat that are acting on the tubing at initial and final condition. At initial condition there is a small force pointing downwards. Determining how WellCat calculated this force was unsuccessful. The impact of the 0,7 lbs on the final result is insignificant.

Initial condition	Pressure test of the tubing



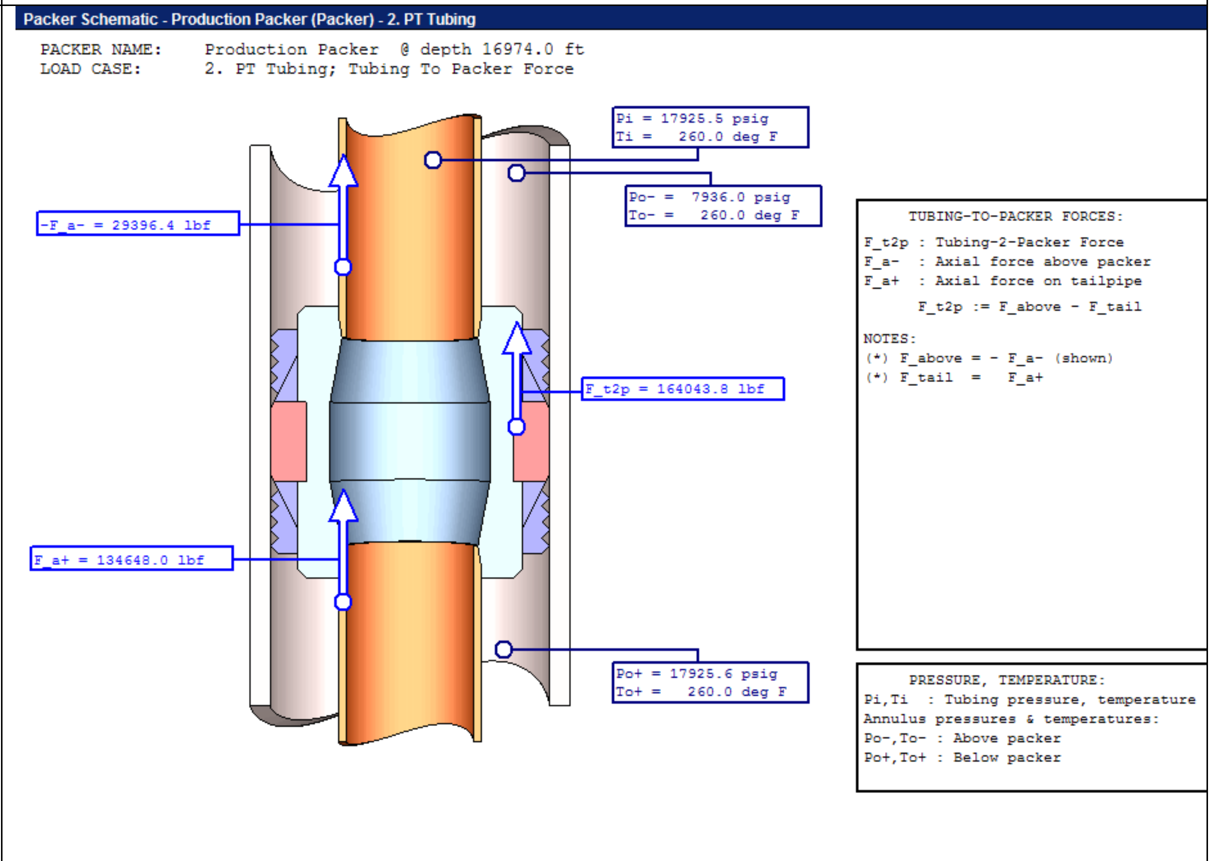


Figure A.2. WellCat illustration of the real force below and above the packer and the tubing to packer force at initial and final condition.

Figure A.2 shows the real force, also called actual force (F_a), calculated by WellCat at initial condition and for the pressure testing of the tubing. The arrow pointing up for $-F_{a-}$ at the pressure testing of the tubing express that the tubing is in tension, F_{a+} is in compression.

	Initial		Final		F_R	
Depth TVD, ft	P_i (psi)	P_o (psi)	P_i (psi)	P_o (psi)	Initial, lbs	Final, lbs
85	37	40	10 033	40	379 518	468 589
1 000	464	468	10 458	468	355 728	444 799
2 000	932	935	10 925	935	329 728	418 799
3 000	1 399	1 403	11 393	1 403	303 728	392 799
4 000	1 867	1 870	11 860	1 870	277 728	366 799
5 000	2 334	2 338	12 328	2 338	251 728	340 799
6 000	2 802	2 805	12 795	2 805	225 728	314 799
7 000	2 370	3 273	13 263	3 273	199 728	288 799
8 000	3 737	3 740	13 730	3 740	173 728	262 799
9 000	4 205	4 208	14 198	4 208	147 728	236 799
10 000	4 672	4 675	14 665	4 675	121 728	210 799
13 700	6 402	6 405	16 395	6 405	25 528	114 599
13 719	6 411	6 414	16 404	6 414	25 034	114 105
15 000	7 010	7 013	17 003	7 013	-8 272	80 799
16 974	7 933	7 936	17 926	7 936	-59 596	29 475
16 974	7 933	7 936	17 926	17 926	-59 596	-134 650
16 975	7 933	7 936	17 926	17 926	-59 622	-134 676

Table 7. Pressure data and actual force before and after pressure testing of the tubing.

Table 7 shows that the axial force at the tubing hanger is higher at the pressure test of the tubing. This is due to the extra force required in order to stretch a freely hanging buckled tubing back to the packer position.

Depth TVD, ft	FE initial, lbs	FE final, lbs	Hole deviation, degrees	HBL, lbs	Effect
85	379 867	306 550	0	0	No buckling
1 000	359 309	286 031	0	0	No buckling
2 000	336 801	263 528	0	0	No buckling
3 000	314 333	241 053	0	0	No buckling
4 000	291 826	218 553	0	0	No buckling
5 000	269 358	196 077	0	0	No buckling
6 000	246 850	173 577	0	0	No buckling
7 000	238 987	151 102	0	0	No buckling
8 000	201 875	128 602	0	0	No buckling
9 000	179 391	106 126	0	0	No buckling
10 000	156 899	83 627	0	0	No buckling
13 700	73 694	428	0	0	No buckling
13 719	73 267	3	0	0	No Buckling
15 000	44 464	-28 800	0	0	Buckling
16 974	71	-73 187	0	0	Buckling
16 974	71	22	0	0	No buckling
16 975	49	0	0	0	No buckling

Table 8. Fictitious force and helical buckling limit vs. depth.

As proved in equation 2.11 the fictitious force has to be zero at the bottom of an open tubing. The reason that the calculated fictitious force at the bottom at initial conditions differs from zero is that the initial inside and outside pressures taken from WellCat are not equal. However, the buckled length of the tubing remains the same because one uses the final fictitious force to find out whether the tubing is buckled.

F_{fz}, fictitious force gradient, lbs/ft	-22,48
Buckled length, ft	**3 255**
TVD at start of buckling, ft	13 719

Table 9. Fictitious force gradient, buckled length and TVD at start of buckling.

Table 9 shows the fictitious force gradient from eq. 3.1 and the buckled length from eq. 3.2. The calculated buckled length by WellCat is 3 259 ft, so the result is very satisfying. One should keep in mind that WellCat and Excel could use different number of significant decimal places.

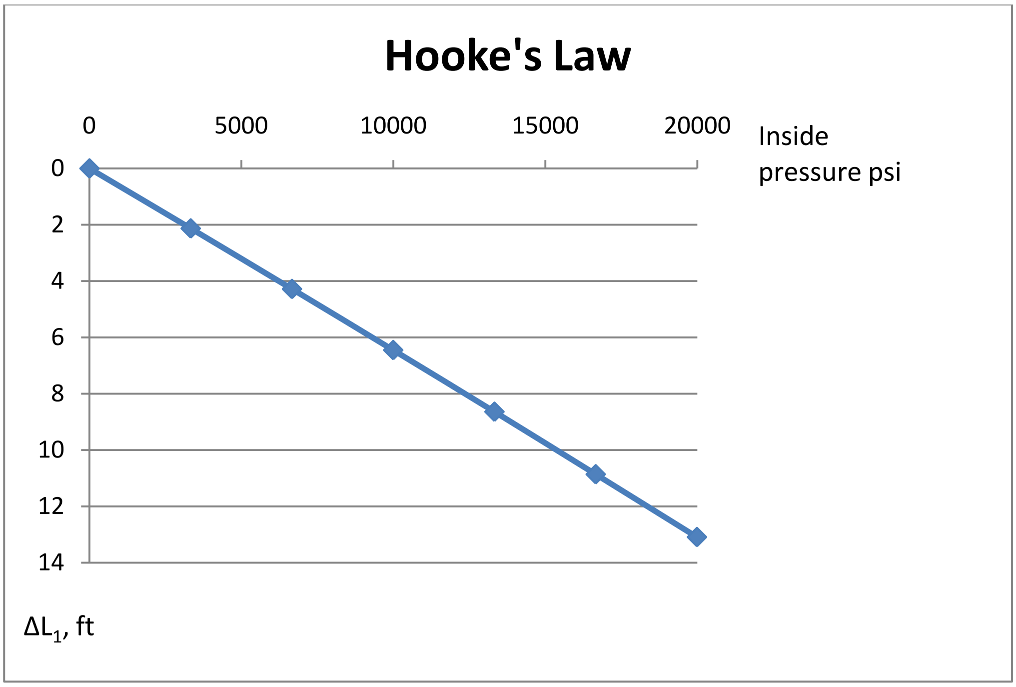


Figure A.3. Effect of the pump pressure on length change of the tubing due to Hooke's law.

Figure A.3 shows that the ΔL_1 is almost linear with increasing inside pressure. Figure A.3 is the sum of Figure A.4 and A.5.

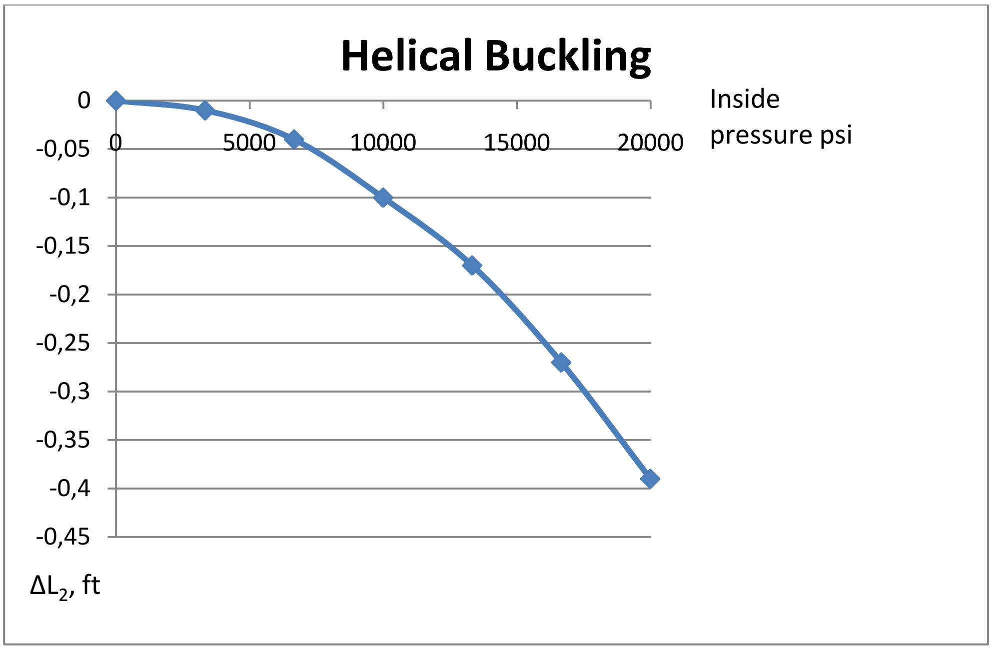


Figure A.4. Effect of pump pressure on the helical buckling length change.

Figure A.4 shows that the helical buckling vs. pressure is not linear. This is probably because the buckled length at low pressures is small and the buckling is less severe. As pressure increases the buckled length increases and the buckling becomes more severe as the pitch decreases.

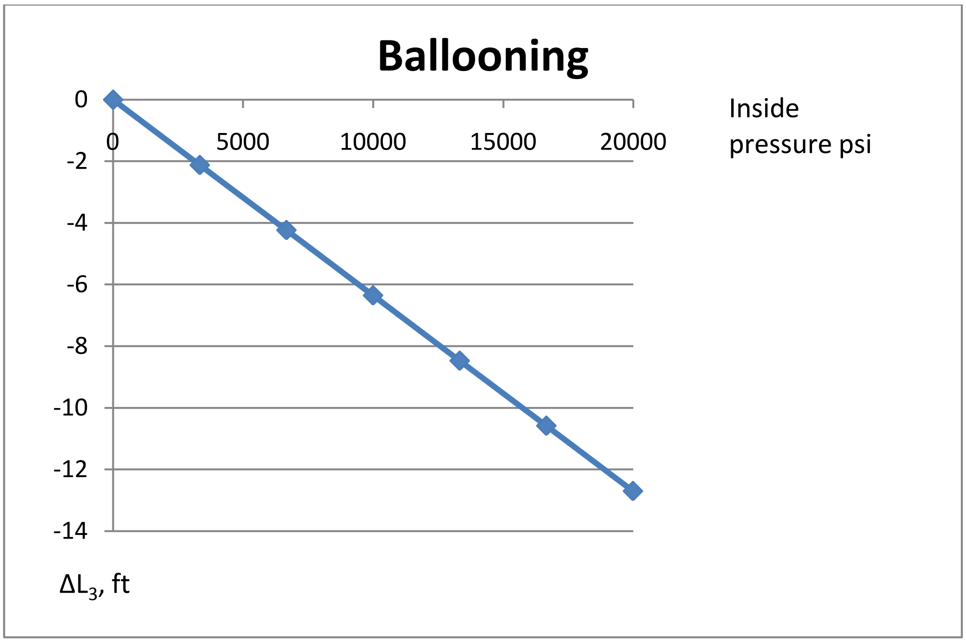


Figure A.5. Effect of pump pressure on the ballooning effect.

Figure A.5 shows that the ballooning effect is linear with the inside pressure.

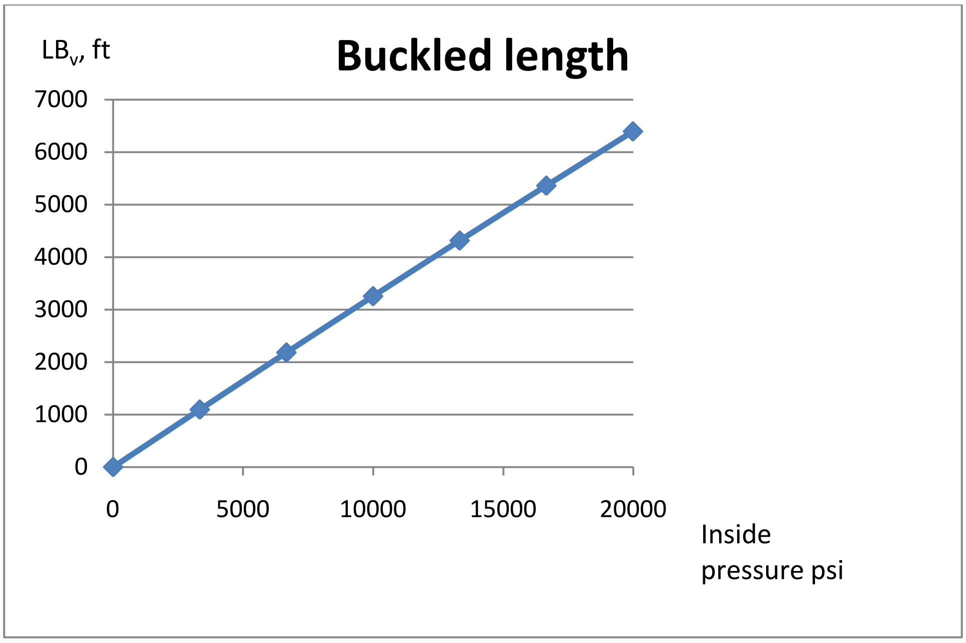


Figure A.6. Effect of pump pressure on the buckled length.

The gradient ΔL/ΔP in Figure A.4 and A.5 is showing that the ballooning effect is the main contributor to the shortening of the tubing and thus the buckled length.

Appendix B

Results Case 2:

(Using method 1)

Input		
PPI1	7 933	Initial pressure inside tubing at packer depth, psi
PPO1, PPO2	7 936	Initial and final pressure outside tubing at packer depth, psi
PPI2	10 933	Final pressure inside tubing at packer depth, psi
DPIS	3 000	Change of pressure inside tubing at surface, psi

Table 10. Pressure input data used for the setting of the hydraulic set packer (stage 1 and 2).

The input pressure data is presented inTable 10. The rest of the input parameters in case 2 is the same as in case 1 can be seen in Table 3.

Calculations	Excel	
DPPI	3 000	Delta pressure inside tubing, psi
F_R	48 736	Force actual, delta piston force, lbs
F_h	22 422	Size of the Hooke's force to get the required length ΔL, lbs
ΔL_1	3,53	Piston effect, Hooke's law, ft
ΔL_2	0	Helical buckling, ft
ΔL_3	-1,91	Ballooning effect, ft
ΔL	1,62	Total length change, ft

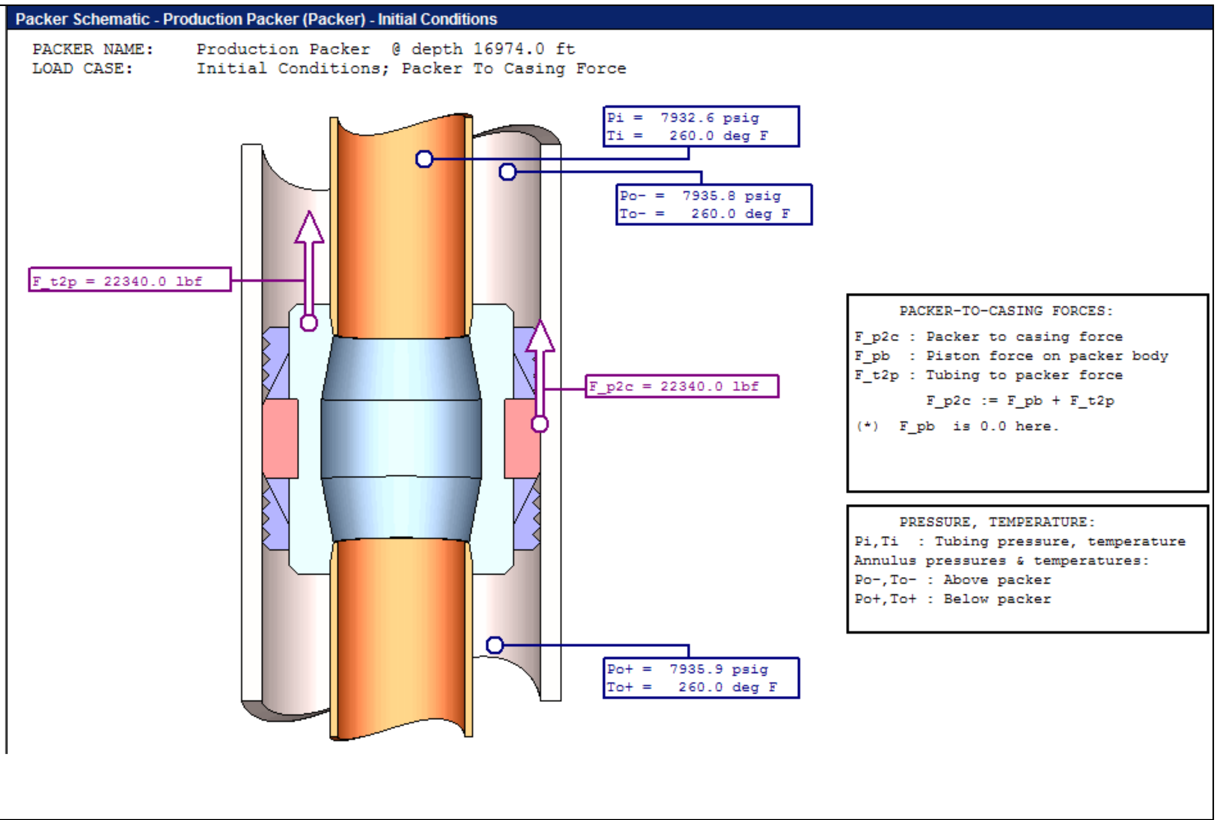
Table 11. Length changes and forces when setting the hydraulic packer (stage 2).

Output	Excel	
F_{pb}	0	Packer body force, lbs
F_{t2p}	22 422	Force tubing to packer, lbs
F_{p2c}	22 422	Force packer to casing, lbs
F_{ah}	401 891	Axial load at tubing hanger, lbs
F_{a-}	-37 223	Axial load above packer, lbs
F_{a+}	-59 645	Axial load below packer, lbs

Table 12. Tubing to packer force and axial forces after setting the hydraulic packer (stage 3).

After the packer is set and the pumps have been turned off the packer force provides for the Hooke's force needed to hold the tubing at the packer position. This is shown by the difference between F_{a-} and F_{a+} is equal to the F_{t2p}. The axial force at the tubing hanger at stage 3 does only differ by 11 lbs to WellCat.

Stage 3



Stage 3

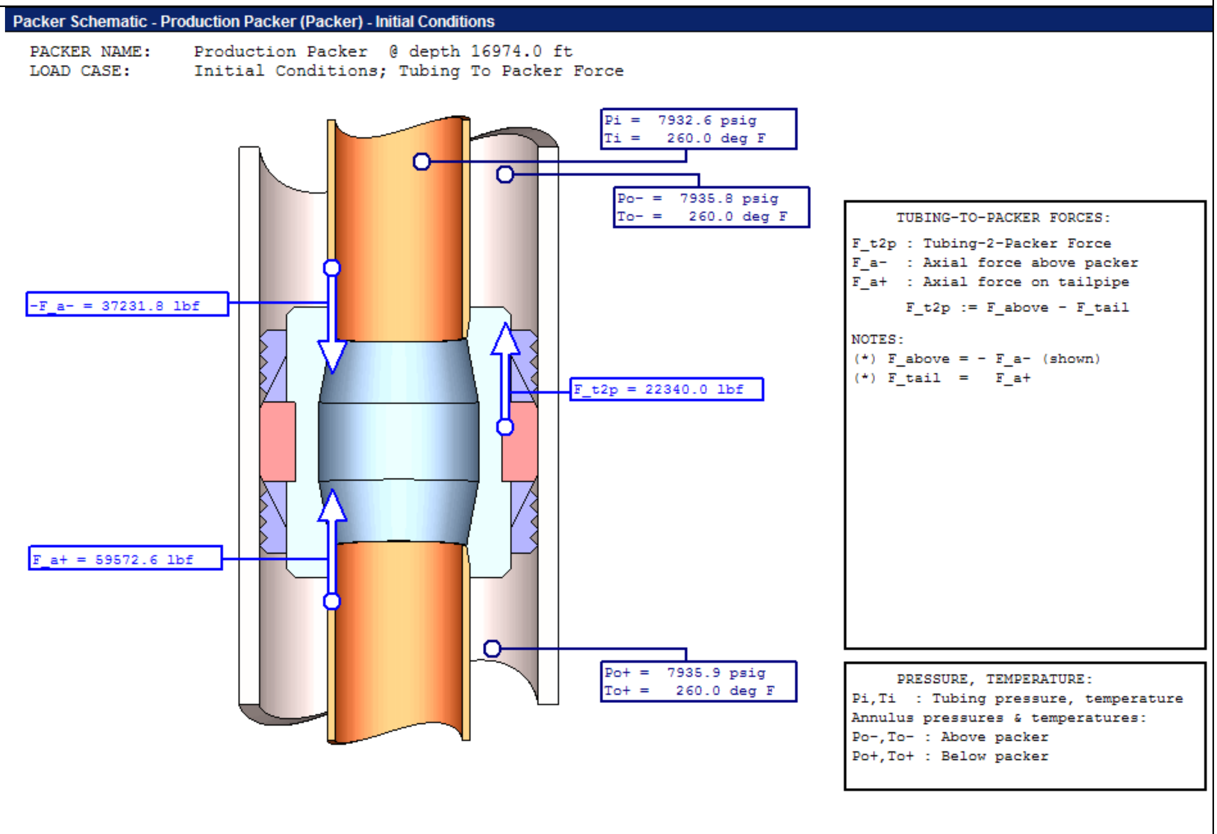


Figure B.1. WellCat illustration of the tubing to packer force, packer to casing force, packer body force and the axial forces above and below the packer at stage 3.

	Stage 1 and 3		F_R	
TVD, ft	P_i, psi	P_o, psi	Stage 1, lbs	Stage 3, lbs
85	37	40	379 469	401 891
1 000	31	461	355 679	378 101
2 000	459	929	329 679	352 101
3 000	927	1 397	303 679	326 101
4 000	1 395	1 865	277 679	300 101
5 000	1 862	2 333	251 679	274 101
6 000	2 330	2 801	225 679	248 101
7 000	2 798	3 269	199 679	222 101
8 000	3 266	3 737	173 679	196 101
9 000	3 734	4 204	147 679	170 101
10 000	4 202	4 672	121 679	144 101
13 700	4 670	6 404	25 479	47 901
14 500	6 401	6 778	4 679	27 101
15 000	6 775	7 012	-8 321	14 101
16 974	7 009	7 936	-59 645	-37 223
16 974	7 933	7 936	-59 645	-59 645
16 975	7 933	7 936	-59 671	-59 671

Table 13. Actual force and pressure data for setting of the hydraulic set packer.

TVD, ft	F_E stage 1, lbs	F_E stage 3, lbs	Hole deviation, degrees	HBL, lbs	Effect
85	379 818	402 240	0	0	No buckling
1 000	359 193	381 615	0	0	No buckling
2 000	336 709	359 130	0	0	No buckling
3 000	314 224	336 646	0	0	No buckling
4 000	291 739	314 161	0	0	No buckling
5 000	269 255	291 676	0	0	No buckling
6 000	246 770	269 191	0	0	No buckling
7 000	224 285	246 707	0	0	No buckling
8 000	201 800	224 222	0	0	No buckling
9 000	179 316	201 737	0	0	No buckling
10 000	156 831	179 253	0	0	No buckling
13 700	73 637	96 059	0	0	No buckling
14 500	55 650	78 071	0	0	No buckling
15 000	44 407	66 829	0	0	No buckling
16 974	22	22 444	0	0	No buckling
16 974	22	22	0	0	No buckling
16 975	0	0	0	0	No buckling

Table 14. Fictitious force at stage 1 and 3.

Input		
PPI1	7 933	Initial pressure inside tubing at packer depth, psi
PPO1, PPO2	7 936	Initial and final pressure outside tubing at packer depth, psi
PPI2	17 926	Final pressure inside tubing at packer depth, psi
DPIS	9 993	Change of pressure inside tubing at surface, psi

Table 15. Input pressures for the pressure test of the tubing (stage 5).

Calculations	Excel	
F_R	75 076	Force actual, delta piston force, lbs
F_h	88 329	Size of the Hooke's force to get the required length L1, lbs
ΔL_1	6,40	Piston effect, Hooke's law, ft
ΔL_2	-0,05	Helical buckling, ft
ΔL_3	-6,35	Ballooning effect, ft

Table 16. Delta piston force, Hooke's force and length changes for the pressure testing of the tubing (stage 5).

Output	Excel	
F_{pb}	336 730	Packer body force, lbs
F_{t2p}	185 827	Force tubing to packer, lbs
F_{p2c}	522 557	Force packer to casing, lbs
F_{ah}	490 291	Axial load at tubing hanger, lbs
F_{a-}	51 177	Axial load above packer, lbs
F_{a+}	-134 650	Axial load below packer, lbs

Table 17. Tubing to packer force and axial forces at the pressure testing of the tubing (stage 5).

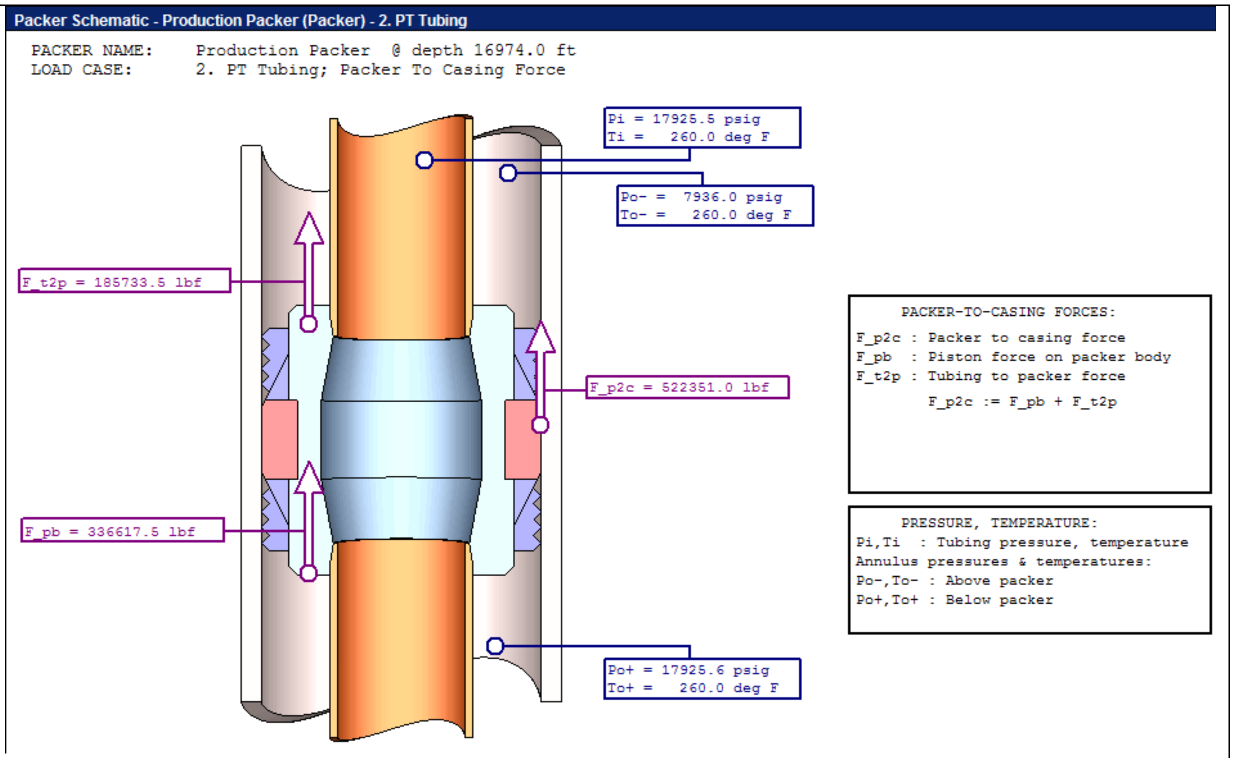
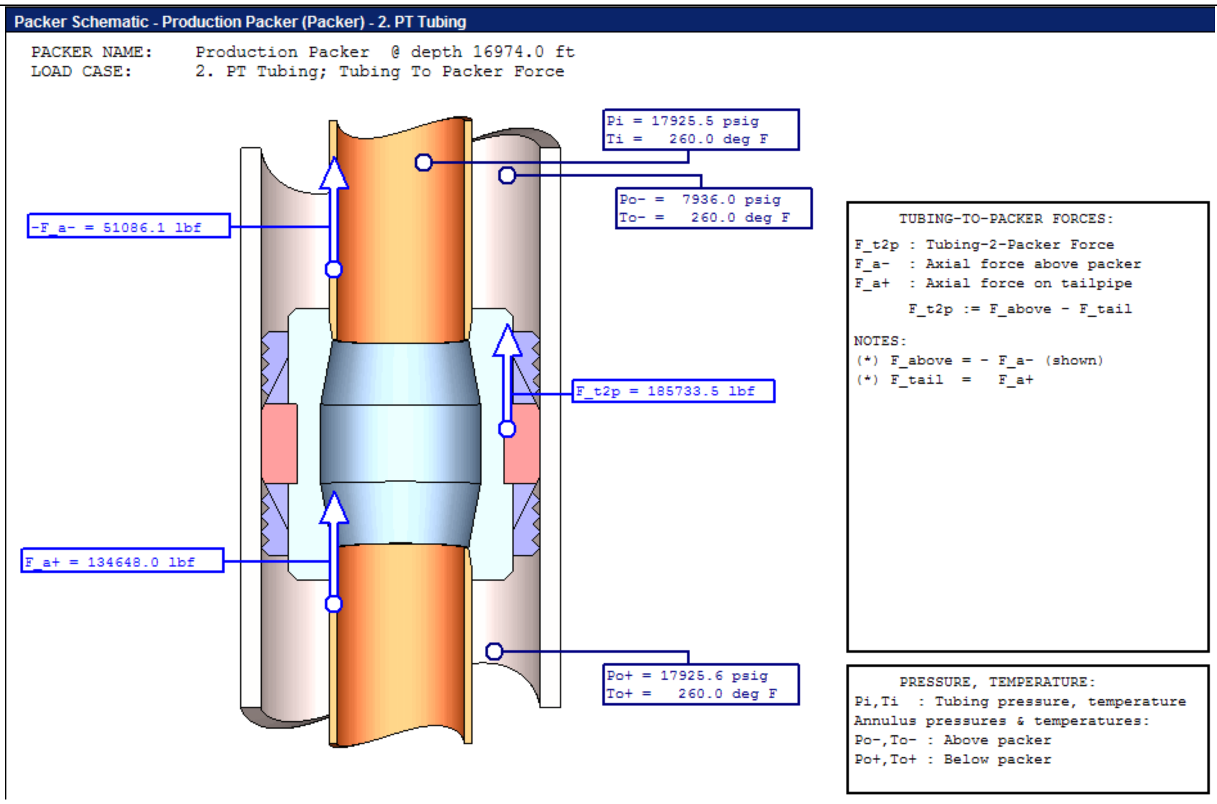
Stage 5	
Stage 5	

Figure B.2. WellCat illustration of the tubing to packer force, packer to casing force, packer body force and the axial forces above and below the packer at stage 5.

Pressure test of the tubing stage 5			
TVD, ft	P_i (psi)	P_o (psi)	F_R, lbs
85	10 033	40	490 291
1 000	10 451	461	466 501
2 000	10 919	929	440 501
3 000	11 387	1 397	414 501
4 000	11 855	1 865	388 501
5 000	12 323	2 333	362 501
6 000	12 791	2 801	336 501
7 000	13 259	3 269	310 501
8 000	13 727	3 737	284 501
9 000	14 194	4 204	258 501
10 000	14 662	4 672	232 501
13 700	16 394	6 404	136 301
14 500	16 768	6 778	115 501
15 000	17 002	7 012	102 501
16 974	17 926	7 936	51 177
16 974	17 926	7 936	-134 650
16 975	17 926	7 936	-134 676

Table 18. Pressure and actual force for the pressure testing of the tubing (stage 5).

TVD, ft	F_E at stage 5, lbs	Hole deviation, degree	HBL, lbs	Effect
85	328 251	0	0	No buckling
1 000	307 675	0	0	No buckling
2 000	285 190	0	0	No buckling
3 000	262 705	0	0	No buckling
4 000	240 221	0	0	No buckling
5 000	217 736	0	0	No buckling
6 000	195 251	0	0	No buckling
7 000	172 766	0	0	No buckling
8 000	150 282	0	0	No buckling
9 000	127 797	0	0	No buckling
10 000	105 312	0	0	No buckling
13 700	22 119	0	0	No buckling
14 500	4 131	0	0	No buckling
15 000	-7 111	0	0	Buckling
16 974	-51 496	0	0	Buckling
16 974	22	0	0	No buckling
16 975	0	0	0	No buckling

Table 19. Fictitious force for the pressure testing of the tubing (stage 5).

As discussed in section 3.3 one can use a mechanical set packer to determine ΔL_2:

Input		
PPI1	7 933	Initial pressure inside tubing at packer depth, psi
PPO1, PPO2	7 936	Initial and final pressure outside tubing at packer depth, psi
PPI2	14 926	Final pressure inside tubing at packer depth, psi
DPIS	6 993	Change of pressure inside tubing at surface, psi

Table 20. Pressures for mechanical set packer and pressure test of the tubing at 6993 psi to determine delta L2.

Calculations	Excel	
DPPI	6 993	Delta pressure inside tubing, psi
F_R	57 538	Force actual, delta piston force, lbs
F_h	62 008	Size of the Hooke's force to get the required length ΔL_1, lbs
ΔL_1	4,49	Piston effect, Hooke's law, ft
ΔL_2	-0,05	Helical buckling, ft
ΔL_3	-4,44	Ballooning effect, ft

Table 21. Real force, Hooke's force and the length changes during the pressure test of the mechanical set packer.

The size of ΔL_2 in Table 21 is the same as in Table 16.

F_{fz}, fictitious force gradient, lbs/ft	-22,48
Buckled length, ft	**2 290**
TVD at start of buckling, ft	14 684

Table 22. Fictitious force gradient, buckled length and TVD at start of buckling.

Table 22 shows that the buckled length of the tubing is 2 290 ft. By looking back at the mechanic set packer with a buckled length of 3 255 ft one can see that the buckled length is reduced by setting the packer in tension.

Appendix C

Results case 3:

Input		
TVD and MD at Packer	9 891	Depth at packer depth, ft
MD at the packer	16 974	Length of Tubing at packer depth, ft
MD end of tubing	16 975	Length MD of tubing at the end, ft
PPI1	4 623	Initial pressure inside tubing at packer depth, psi
PPO1	4 625	Initial pressure outside tubing at packer depth, psi
PPI2	14 616	Final pressure inside tubing at packer depth, psi
PPO2	4 624	Final pressure outside tubing at packer depth, psi

Table 23. Input data used for the calculations in case 3.

Table 23 represents only the input parameters that have been changed since case 1.

Calculations	Excel	
DPPI	9 993	Delta pressure inside the tubing, psi
F_R	75 076	Force actual, delta piston force, lbs
F_h	87 801	Size of the Hooke's force to get the required length ΔL_1, lbs
ΔL_1	6,36	Piston effect, Hooke's law, ft
ΔL_2	-0,01	Helical buckling, ft
ΔL_3	-6,35	Ballooning effect , ft

Table 24. Forces and length changes.

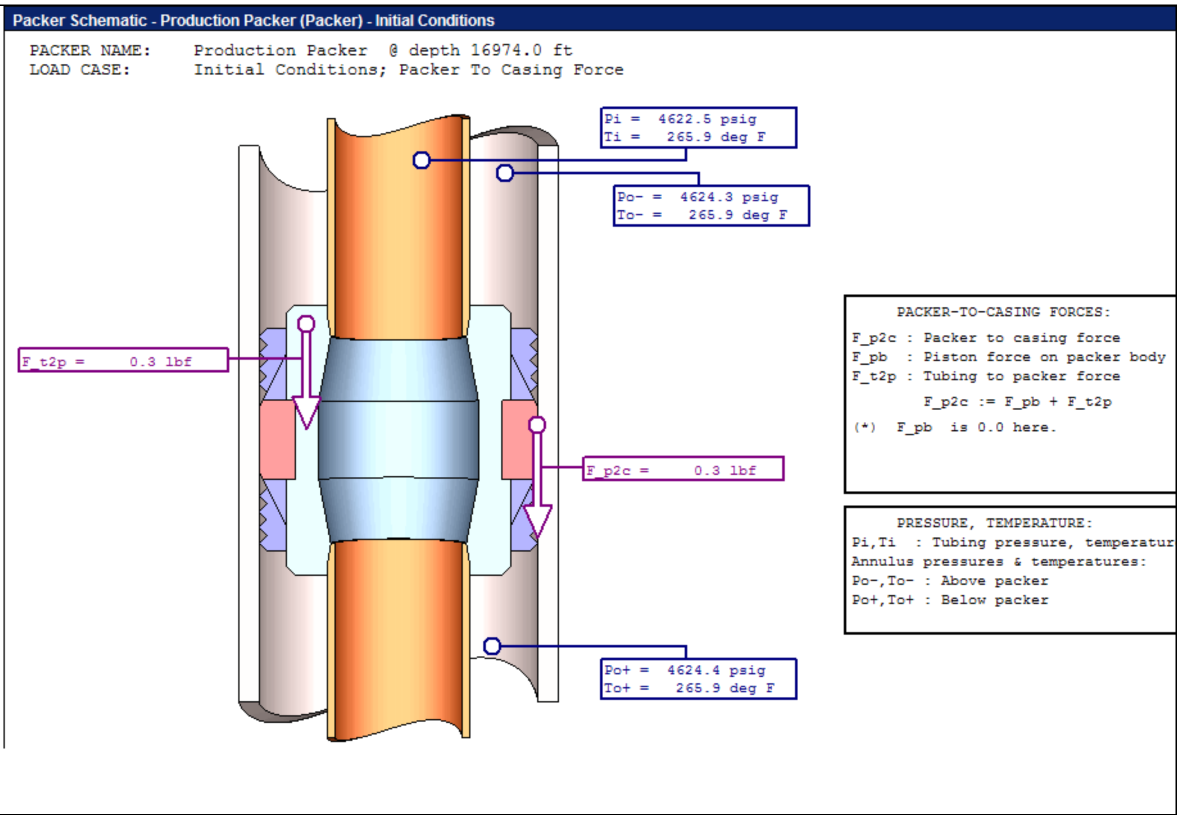
By comparing ΔL_2 Table 24 and Table 5 (mechanic set packer in vertical well) one can see that ΔL_2 is strongly affected by the well angle. It's only about 1/10th the size of ΔL_2 in case 1. To find ΔL_2, it was first set to be zero in order to find an approximate value of the fictitious force just above the packer. F_{fp} was found to be about 1,3 times F_{Paslay} which means that the tubing is only laterally buckled. Then ΔL_2 was determined by solving equation 4.12. Then new length changes, packer forces, axial force and fictitious force were calculated. Then a new ΔL_2 was calculated by using eq. 4.12. This cycle was repeated until ΔL_2 converged. Only the final results are presented in the tables.

Output	Excel	
F_{pb}	336 748	Packer body force, lbs
F_{t2p}	162 877	Force tubing to packer, lbs
F_{p2c}	499 625	Force packer to casing, lbs
F_{ah}	308 027	Axial load at tubing hanger, lbs
F_{a-}	53 071	Axial load above packer, lbs
F_{a+}	-109 806	Axial load below packer, lbs

Table 25. Packer forces.

The tubing to packer force in Table 25 is spot on the calculated result by WellCat in Figure. The packer body force differs by 100 lbs. This is because WellCat uses 9 990 psi as the pressure differential. The packer body force in Table 26 uses 9 993 psi as the pressure differential. The axial forces in Table 25 are spot on the axial forces in C.1.

Initial condition



Pressure test of the tubing

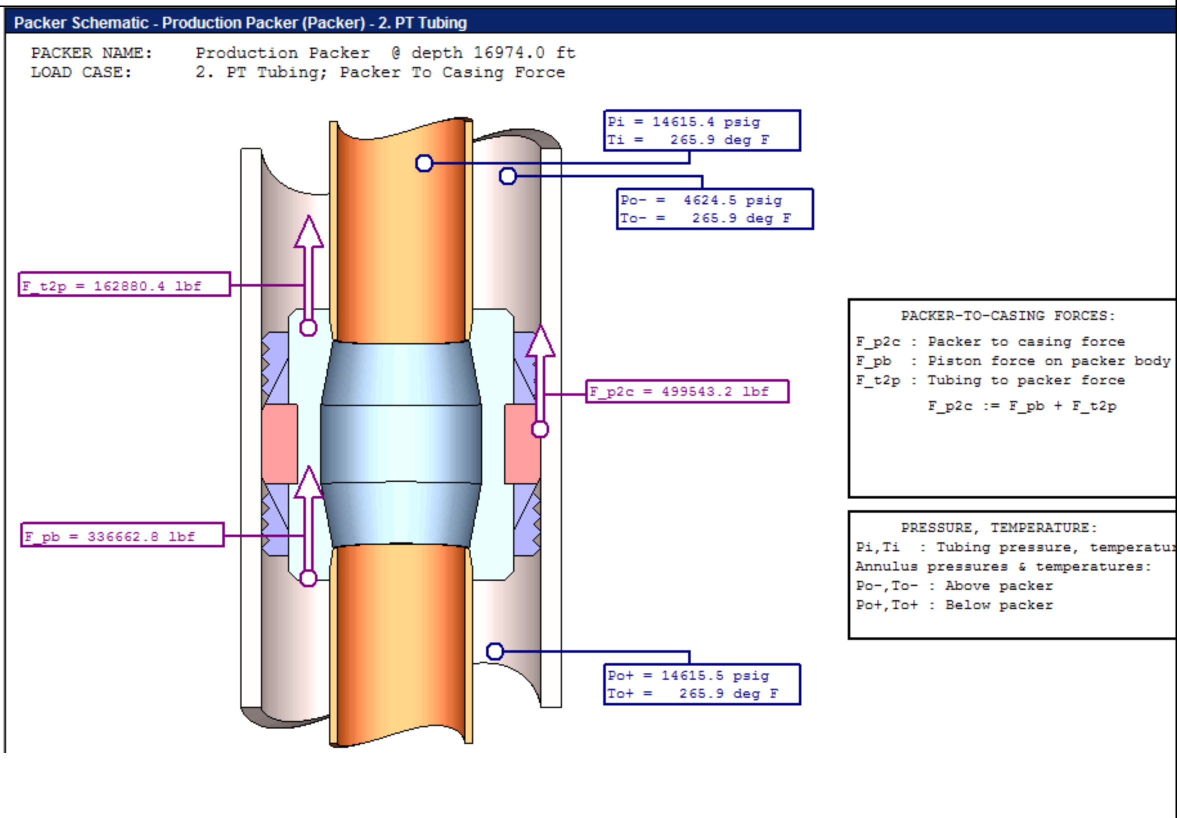
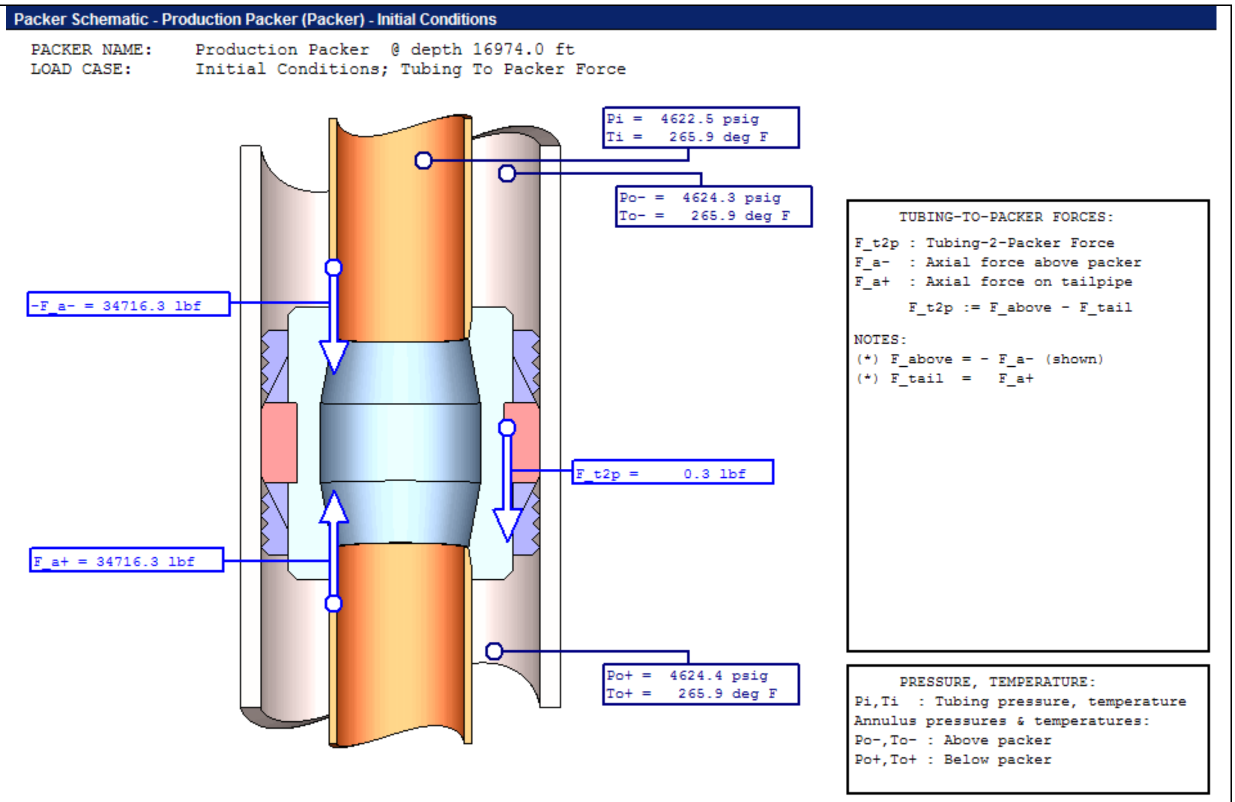


Figure C.1. WellCat illustration of the tubing to packer force, packer to casing force and packer body force at initial and final condition.

IC



2. PT Tubing

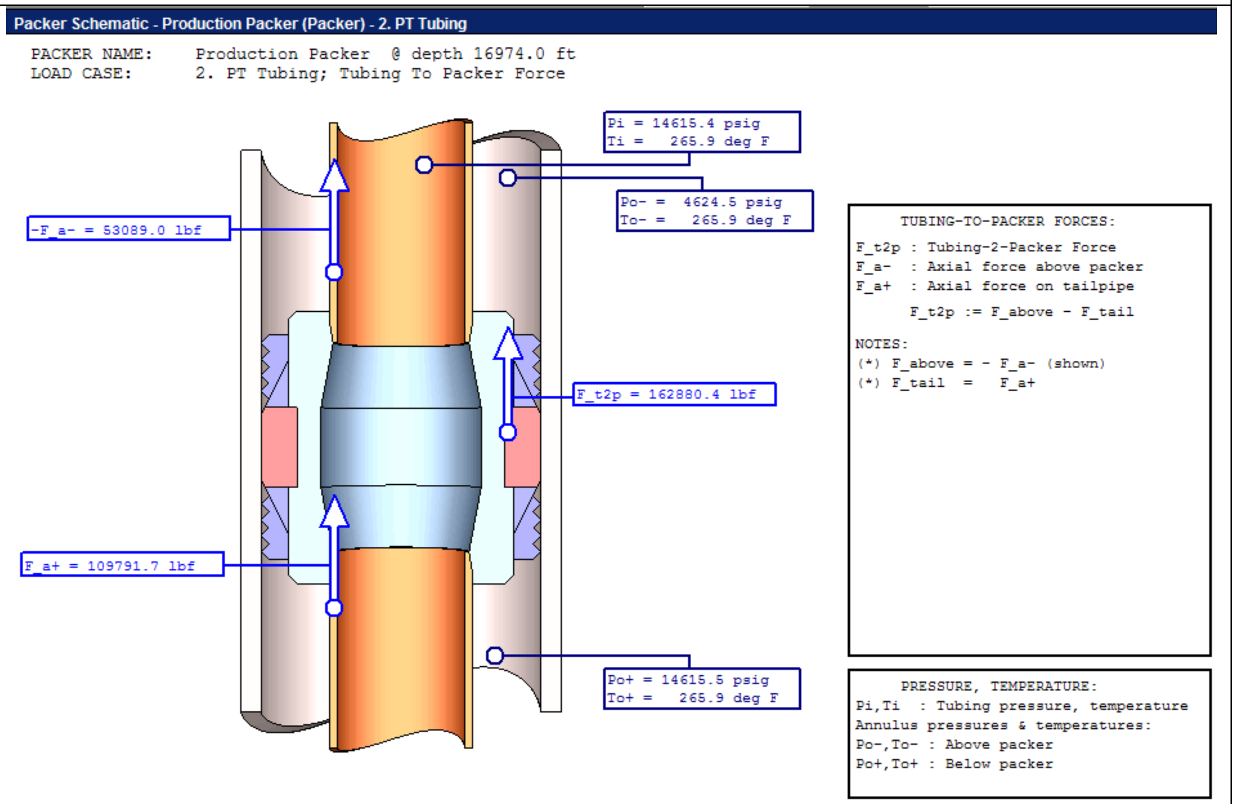


Figure C.2. WellCat illustration of the real force below and above the packer and the tubing to packer force at initial and final condition.

		Initial pressures		Final pressures		F_R	
MD, ft	TVD, ft	P_i, psi	P_o, psi	P_i, psi	P_o, psi	Initial, lbs	Final, lbs
85	85	38	40	10 033	40	220 226	308 027
1 500	1 500	700	701	10 694	701	183 436	271 237
1 600	1 600	746	748	10 741	748	180 836	268 637
1 700	1 700	793	795	10 787	795	178 236	266 037
1 800	1 799	839	841	10 834	841	175 662	263 463
1 900	1 897	885	887	10 880	887	173 114	260 915
2 000	1 994	931	932	10 925	933	170 592	258 393
2 100	2 090	975	977	10 970	977	168 096	255 897
2 200	2 184	1 019	1 021	11 014	1 021	165 652	253 453
2 300	2 277	1 063	1 064	11 057	1 065	163 234	251 035
2 400	2 367	1 105	1 107	11 099	1 107	160 894	248 695
2 500	2 455	1 146	1 148	11 140	1 148	158 606	246 407
2 600	2 540	1 186	1 188	11 180	1 188	156 396	244 197
2 700	2 623	1 224	1 226	11 219	1 226	154 238	242 039
2 800	2 702	1 261	1 263	11 256	1 263	152 184	239 985
2 900	2 778	1 297	1 299	11 291	1 299	150 208	238 009
3 000	2 850	1 331	1 333	11 325	1 333	148 336	236 137
3 100	2 919	1 363	1 365	11 357	1 365	146 542	234 343
3 200	2 984	1 393	1 395	11 388	1 395	144 852	232 653
3 300	3 045	1 422	1 424	11 416	1 424	143 266	231 067
3 400	3 102	1 448	1 450	11 443	1 450	141 784	229 585
3 500	3 154	1 473	1 475	11 467	1 475	140 432	228 233
3 600	3 204	1 496	1 498	11 490	1 498	139 132	226 933
16 750	9 779	4 570	4 572	14 563	4 572	-31 818	55 983
16 974	9 891	4 623	4 624	14 615	4 624	-34 730	53 071
16 974	9 891	4 623	4 624	14 615	14 615	-34 730	-109 806
16 975	9 891	4 623	4 625	14 616	14 616	-34 730	-109 806

Table 26. Pressure and actual force at the pressure testing of the tubing.

MD, ft	TVD, ft	F_E initial, lbs	F_E final, lbs	Hole angle, degrees	HBL Dawson and Paslay (1984)	Effect
85	85	220 554	145 990	0	0	No buckling
1 500	1 500	188 734	114 175	0	0	No buckling
1 600	1 600	186 485	111 926	3	-13 814	No buckling
1 700	1 700	184 235	109 676	6	-19 522	No buckling
1 800	1 799	182 010	107 450	9	-23 882	No buckling
1 900	1 897	179 807	105 249	12	-27 532	No buckling
2 000	1 994	177 626	103 067	15	-30 719	No buckling
2 100	2 090	175 467	100 909	18	-33 566	No buckling
2 200	2 184	173 354	98 796	21	-36 147	No buckling
2 300	2 277	171 260	96 703	24	-38 509	No buckling
2 400	2 367	169 237	94 680	27	-40 685	No buckling
2 500	2 455	167 258	92 702	30	-42 696	No buckling
2 600	2 540	165 348	90 791	33	-44 562	No buckling
2 700	2 623	163 479	88 923	36	-46 293	No buckling
2 800	2 702	161 703	87 147	39	-47 901	No buckling
2 900	2 778	159 995	85 438	42	-49 393	No buckling
3 000	2 850	158 378	83 822	45	-50 775	No buckling
3 100	2 919	156 825	82 271	48	-52 053	No buckling
3 200	2 984	155 363	80 808	51	-53 230	No buckling
3 300	3 045	153 991	79 437	54	-54 311	No buckling
3 400	3 102	152 708	78 153	57	-55 297	No buckling
3 500	3 154	151 540	76 986	60	-56 192	No buckling
3 600	3 204	150 415	75 861	60	-56 192	No buckling
16 750	9 779	2 560	-71 975	60	-56 192	Buckling
16 974	9 891	41	-74 493	60	-56 192	Buckling
16 974	9 891	41	-2	60	-56 192	No buckling
16 975	9 891	0	0	60	-56 192	No buckling

Table 27. Fictitious force and helical buckling limit vs. depth.

F_{fs}, fictitious force gradient in the sail section, lbs/ft	-11,24
Buckled length, ft	**1 628**
MD at start of buckling, ft	15 346

Table 28. Fictitious force gradient, buckled length and MD at start of buckling.

Looking back at the mechanic set packer in the vertical well (case 1) the buckled length was 3 255 ft. Compared to the buckled length in Table 28 one can see that the buckled length has been reduced as a result of well angle. Notice that the fictitious force gradient is less in a sail section than a vertical section.

Appendix D

Results Case 4:

Input		
TVD at packer and end of tubing	9 891	Depth at packer depth, ft
MD at packer	16 974	Length of Tubing at packer depth, ft
TVD end of tubing	9 891	Length TVD of tubing at the end, ft
MD end of tubing	16 975	Length MD of tubing at the end, ft
PPI1	4 623	Initial pressure inside tubing at packer depth, psi
PPO1, PPO2	4 625	Initial and final pressure outside tubing at packer depth, psi
PPI2	5 123	Final pressure inside tubing at packer depth, psi

Table 29. Pressure input data used for the setting of the hydraulic set packer for case 4 (stage 1 and 2).

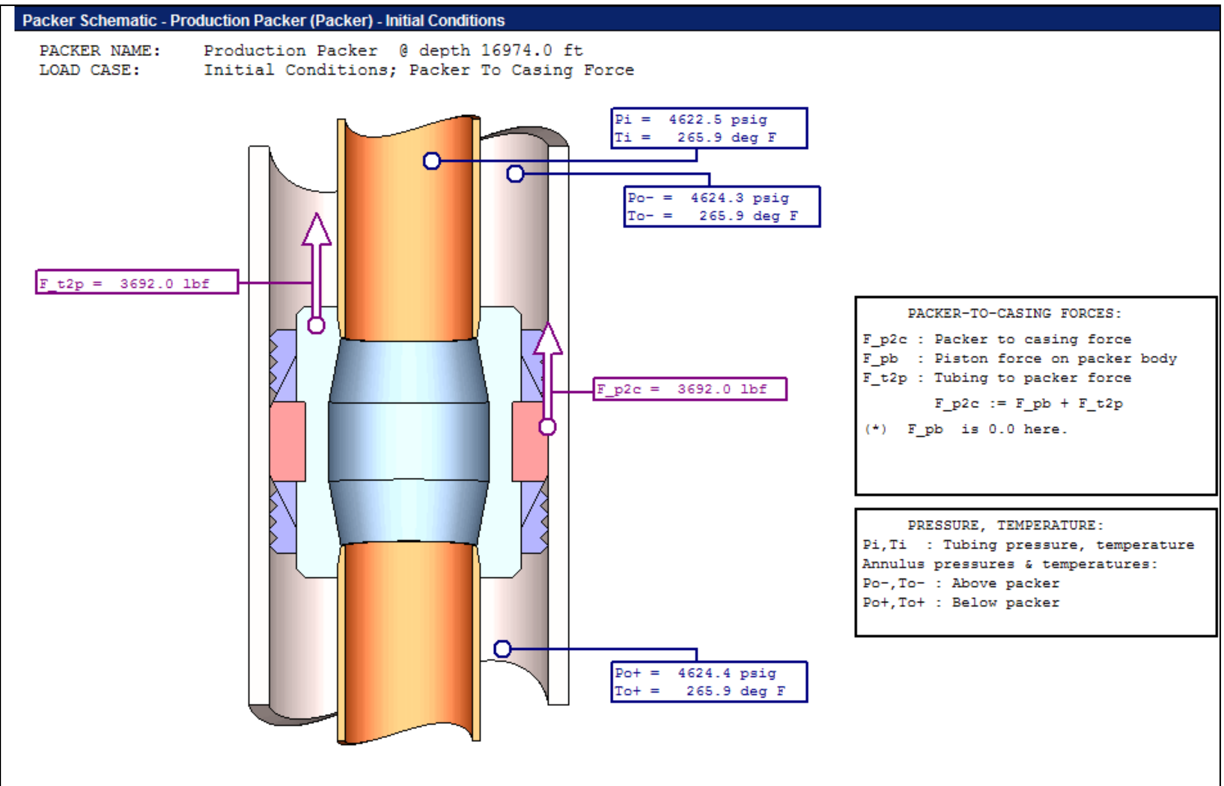
Calculations	Excel	
DPPI	500	Delta pressure inside tubing, psi
F_R	8 123	Force actual, lbs
F_h	3 737	Size of the Hooke's force to get the required length ΔL, lbs
ΔL_1	0,59	Piston effect, Hooke's law, ft
ΔL_3	-0,32	Ballooning effect, ft
ΔL	0,27	Total length change, ft

Table 30. Length changes and forces when setting the hydraulic set packer.

Output	Excel	
F_{pb}	0	Packer body force, lbs
F_{t2p}	3 737	Force tubing to packer, lbs
F_{p2c}	3 737	Force packer to casing, lbs
F_{ah}	223 961	Axial load at tubing hanger, lbs
F_{a-}	-30 995	Axial load above packer, lbs
F_{a+}	-34 732	Axial load below packer, lbs

Table 31. Tubing to packer force and axial forces when setting the hydraulic set packer (stage 3).

Stage 3



Stage 3

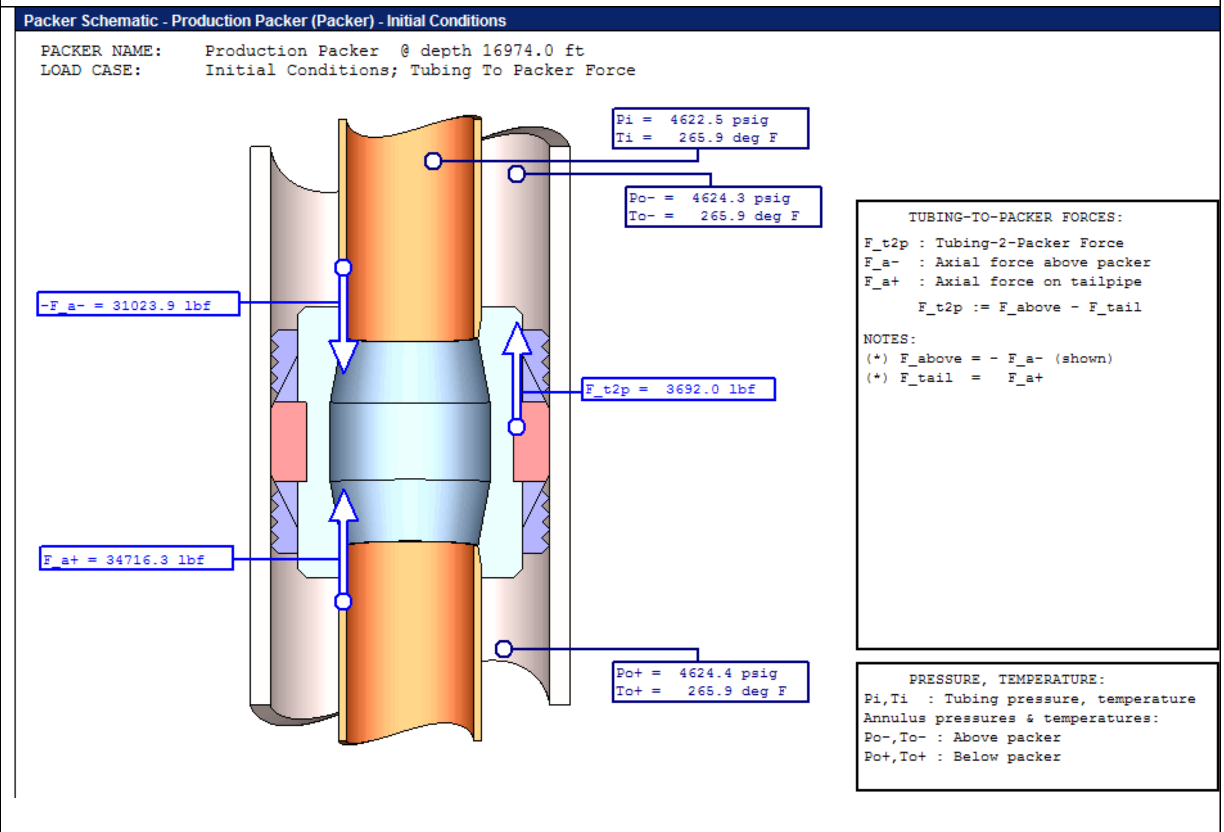


Figure D.1. WellCat illustration of the tubing to packer force, packer to casing force, packer body force and the axial forces above and below the packer at stage 3.

		Stage 1 and 3		F_R	
MD, ft	TVD, ft	P_i, psi	P_o, psi	Stage 1, lbs	Stage 3, lbs
85	85	37	37	220 224	223 961
1 500	1 500	706	706	183 434	187 171
1 600	1 600	752	752	180 834	184 571
1 700	1 700	799	799	178 234	181 971
1 800	1 799	845	845	175 660	179 397
1 900	1 897	891	891	173 112	176 849
2 000	1 994	936	936	170 590	174 327
2 100	2 090	981	981	168 094	171 831
2 200	2 184	1 025	1 025	165 650	169 387
2 300	2 277	1 068	1 068	163 232	166 969
2 400	2 367	1 110	1 110	160 892	164 629
2 500	2 455	1 151	1 151	158 604	162 341
2 600	2 540	1 191	1 191	156 394	160 131
2 700	2 623	1 230	1 230	154 236	157 973
2 800	2 702	1 267	1 267	152 182	155 919
2 900	2 778	1 302	1 302	150 206	153 943
3 000	2 850	1 336	1 336	148 334	152 071
3 100	2 919	1 368	1 368	146 540	150 277
3 200	2 984	1 398	1 398	144 850	148 587
3 300	3 045	1 427	1 427	143 264	147 001
3 400	3 102	1 454	1 454	141 782	145 519
3 500	3 154	1 478	1 478	140 430	144 167
3 600	3 204	1 501	1 501	139 130	142 867
16 750	9 779	4 571	4 571	-31 820	-28 083
16 974	9 891	4 623	4 623	-34 732	-30 995
16 974	9 891	4 623	4 623	-34 732	-34 732
16 975	9 891	4 623	4 623	-34 732	-34 732

Table 32. Actual force and pressure data for setting of the hydraulic set packer (stage 1 and 3).

MD, ft	TVD, ft	F_E Stage 1, lbs	F_E Stage 3, lbs	Hole deviation, degrees	HBL	Effect
85	85	220 502	224 239	0	0	No buckling
1 500	1 500	188 735	192 472	0	0	No buckling
1 600	1 600	186 486	190 223	3	-13 814	No buckling
1 700	1 700	184 237	187 974	6	-19 522	No buckling
1 800	1 799	182 010	185 747	9	-23 882	No buckling
1 900	1 897	179 806	183 543	12	-27 532	No buckling
2 000	1 994	177 624	181 361	15	-30 719	No buckling
2 100	2 090	175 465	179 201	18	-33 566	No buckling
2 200	2 184	173 351	177 087	21	-36 147	No buckling
2 300	2 277	171 259	174 995	24	-38 509	No buckling
2 400	2 367	169 234	172 971	27	-40 685	No buckling
2 500	2 455	167 255	170 992	30	-42 696	No buckling
2 600	2 540	165 343	169 080	33	-44 562	No buckling
2 700	2 623	163 476	167 213	36	-46 293	No buckling
2 800	2 702	161 699	165 436	39	-47 901	No buckling
2 900	2 778	159 990	163 727	42	-49 393	No buckling
3 000	2 850	158 370	162 107	45	-50 775	No buckling
3 100	2 919	156 818	160 555	48	-52 053	No buckling
3 200	2 984	155 356	159 093	51	-53 230	No buckling
3 300	3 045	153 984	157 721	54	-54 311	No buckling
3 400	3 102	152 702	156 439	57	-55 297	No buckling
3 500	3 154	151 533	155 269	60	-56 192	No buckling
3 600	3 204	150 408	154 145	60	-56 192	No buckling
16 750	9 779	2 519	6 256	60	-56 192	No buckling
16 974	9 891	0	3 737	60	-56 192	No buckling
16 974	9 891	0	0	60	-56 192	No buckling
16 975	9 891	0	0	60	-56 192	No buckling

Table 33. Fictitious force and helical buckling limit vs. Depth (stage 1 and 3).

Input		
PPI1	4 623	Pressure inside tubing at packer depth at stage 3, psi
PPO1	4 625	Pressure outside tubing at packer depth at stage 3, psi
PPI2	14 616	Pressure inside tubing at packer depth at stage at stage 5, psi
PPO2	4 624	Pressure outside tubing at packer depth at stage 5, psi

Table 34. Input for the pressure testing of the tubing (stage 3 and 5).

Calculations	Excel	
DPPI	9 993	Delta pressure inside tubing, psi
F_R	75 076	Force actual, lbs
F_h	87 750	Size of the Hooke's force to get the required length ΔL_1, lbs
ΔL_1	6,36	Piston effect, Hooke's law, ft
ΔL_2	-0,01	Helical buckling, ft
ΔL_3	-6,35	Ballooning effect , ft

Table 35. Length changes and forces for the pressure testing of the tubing (stage 5).

Output	Excel	
F_{pb}	336 730	Packer body force, lbs
F_{t2p}	166 563	Force tubing to packer, lbs
F_{p2c}	503 293	Force packer to casing, lbs
F_{ah}	311 711	Axial load at tubing hanger, lbs
F_{a-}	56 755	Axial load above packer, lbs
F_{a+}	-109 808	Axial load below packer, lbs

Table 36. Tubing to packer force and axial forces for the pressure testing of the tubing (stage 5).

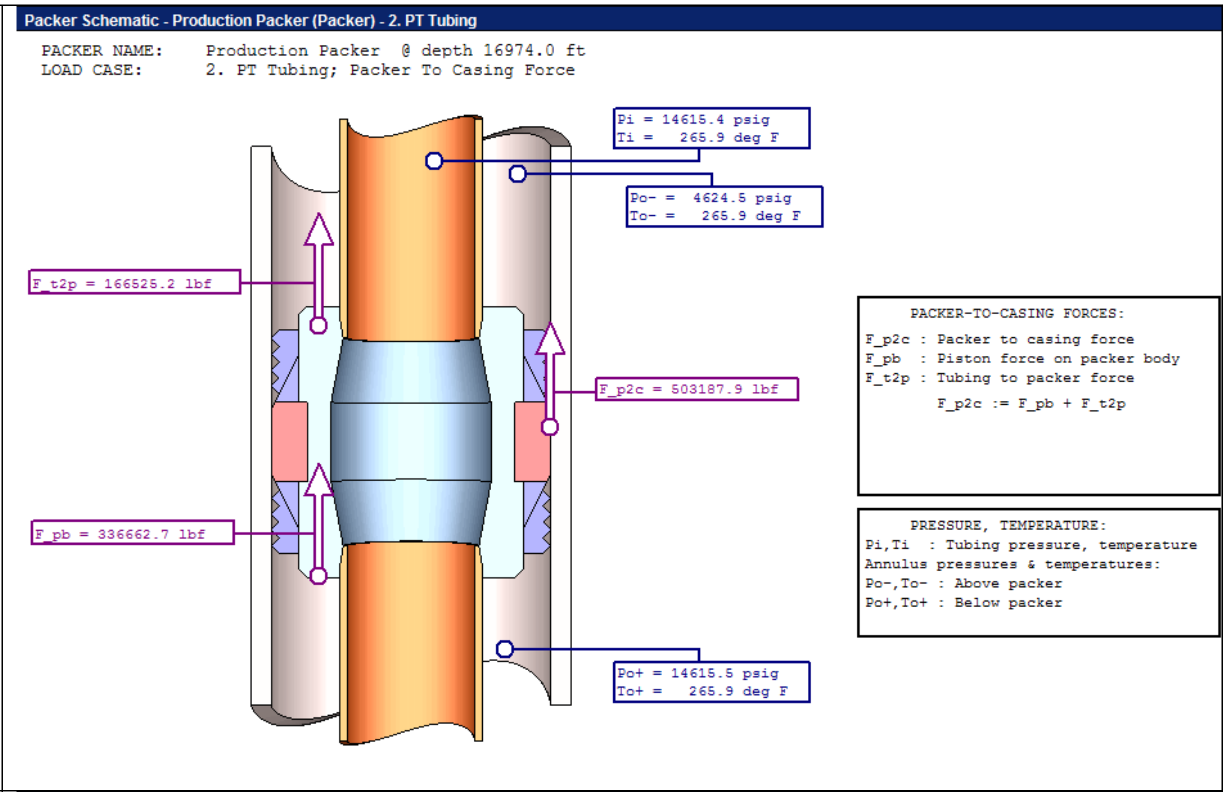
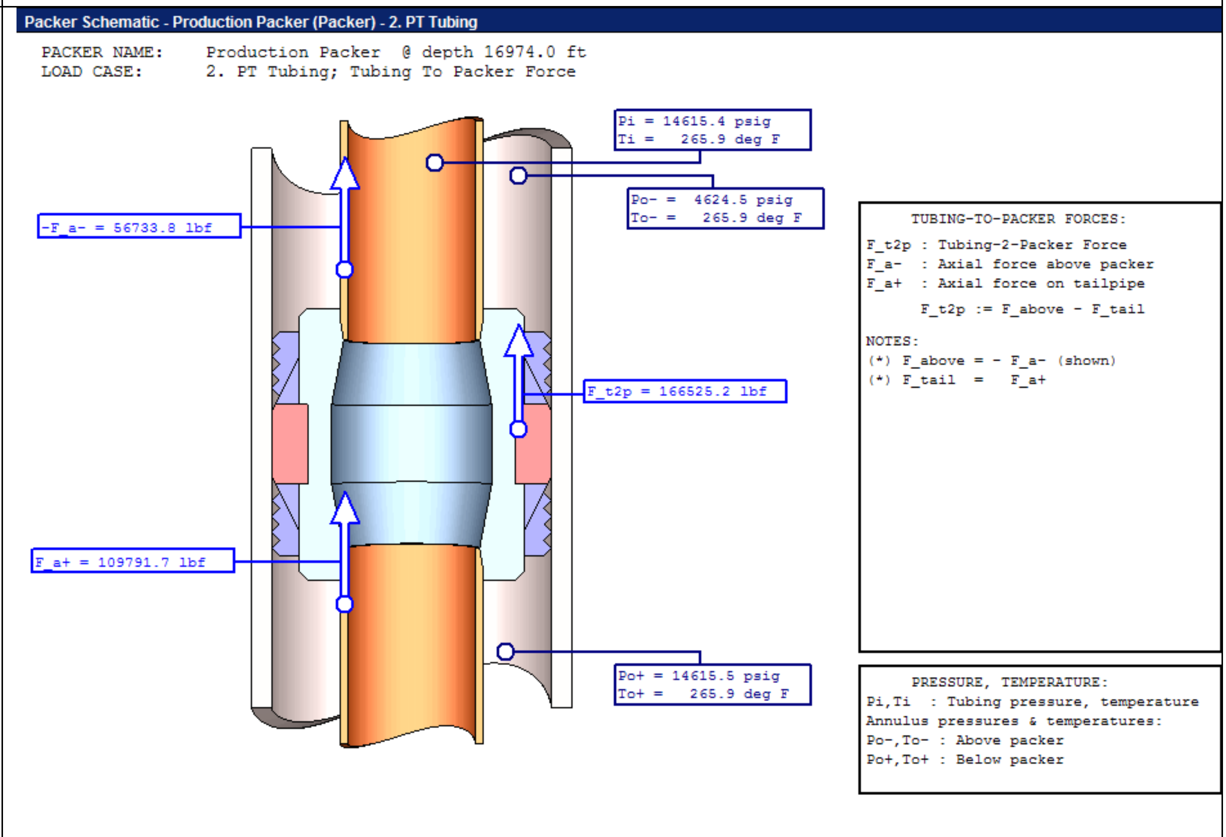
Stage 5	
Stage 5	

Figure D.2. WellCat illustration of the tubing to packer force, packer to casing force, packer body force and the axial forces above and below the packer at stage 5.

Pressure test of the tubing, stage 5				
MD (ft)	Depth (ft TVD)	P_i, psi	P_o, psi	F_R at stage 5, lbs
85	85	10 033	37	311 711
1 500	1 500	14 616	706	274 921
1 600	1 600	14 616	752	272 321
1 700	1 700	14 616	799	269 721
1 800	1 799	14 616	845	267 147
1 900	1 897	14 616	891	264 599
2 000	1 994	14 616	936	262 077
2 100	2 090	14 616	981	259 581
2 200	2 184	14 616	1 025	257 137
2 300	2 277	14 616	1 068	254 719
2 400	2 367	14 616	1 110	252 379
2 500	2 455	14 616	1 151	250 091
2 600	2 540	14 616	1 191	247 881
2 700	2 623	14 616	1 230	245 723
2 800	2 702	14 616	1 267	243 669
2 900	2 778	14 616	1 302	241 693
3 000	2 850	14 616	1 336	239 821
3 100	2 919	14 616	1 368	238 027
3 200	2 984	14 616	1 398	236 337
3 300	3 045	14 616	1 427	234 751
3 400	3 102	14 616	1 454	233 269
3 500	3 154	14 616	1 478	231 917
3 600	3 204	14 616	1 501	230 617
16 750	9 779	14 616	4 571	59 667
16 974	9 891	14 616	4 623	56 755
16 974	9 891	14 616	14 616	-109 808
16 975	9 891	14 616	14 616	-109 808

Table 37. Pressure and real force for the pressure testing of the tubing.

Pressure test of tubing, stage 5					
MD, ft	TVD, ft	F_E, lbs	Hole deviation	HBL	Effect
85	85	149 600	0	0	No buckling
1 500	1 500	117 882	0	0	No buckling
1 600	1 600	115 633	3	-13 814	No buckling
1 700	1 700	113 383	6	-19 522	No buckling
1 800	1 799	111 157	9	-23 882	No buckling
1 900	1 897	108 952	12	-27 532	No buckling
2 000	1 994	106 771	15	-30 719	No buckling
2 100	2 090	104 611	18	-33 566	No buckling
2 200	2 184	102 497	21	-36 147	No buckling
2 300	2 277	100 405	24	-38 509	No buckling
2 400	2 367	98 381	27	-40 685	No buckling
2 500	2 455	96 402	30	-42 696	No buckling
2 600	2 540	94 490	33	-44 562	No buckling
2 700	2 623	92 623	36	-46 293	No buckling
2 800	2 702	90 846	39	-47 901	No buckling
2 900	2 778	89 136	42	-49 393	No buckling
3 000	2 850	87 517	45	-50 775	No buckling
3 100	2 919	85 965	48	-52 053	No buckling
3 200	2 984	84 503	51	-53 230	No buckling
3 300	3 045	83 131	54	-54 311	No buckling
3 400	3 102	81 849	57	-55 297	No buckling
3 500	3 154	80 679	60	-56 192	No buckling
3 600	3 204	79 555	60	-56 192	No buckling
16 750	9 779	-68 334	60	-56 192	Buckling
16 974	9 891	-70 853	60	-56 192	Buckling
16 974	9 891	0	60	-56 192	No buckling
16 975	9 891	0	60	-56 192	No buckling

Table 38. Fictitious force for the pressure testing of the tubing.

F_{fs}, fictitious force gradient, lbs/ft	-11,25
Buckled length, ft	**1 304**
TVD at start of buckling	15 670

Table 39. Fictitious force gradient, buckled length and MD at the beginning of the buckled tubing.

Remember that the hydraulic set packer was set at 500 psi. If 3 000 psi were used as setting pressure no buckling would occur at the pressure test of the tubing.