Problem 1: Design of liner and tieback string

Given data:

Liner interval:	4650 m-5100 m (well bottom)
Tie-back interval:	4650 m- 0
Top cement:	4650 m
Depth of test packer:	4950 m
Mud weight:	2.2. s.g.
Pore pressure:	2.11 s.g. at 5000 m
Density of reservoir fluid:	0.547 s.g.

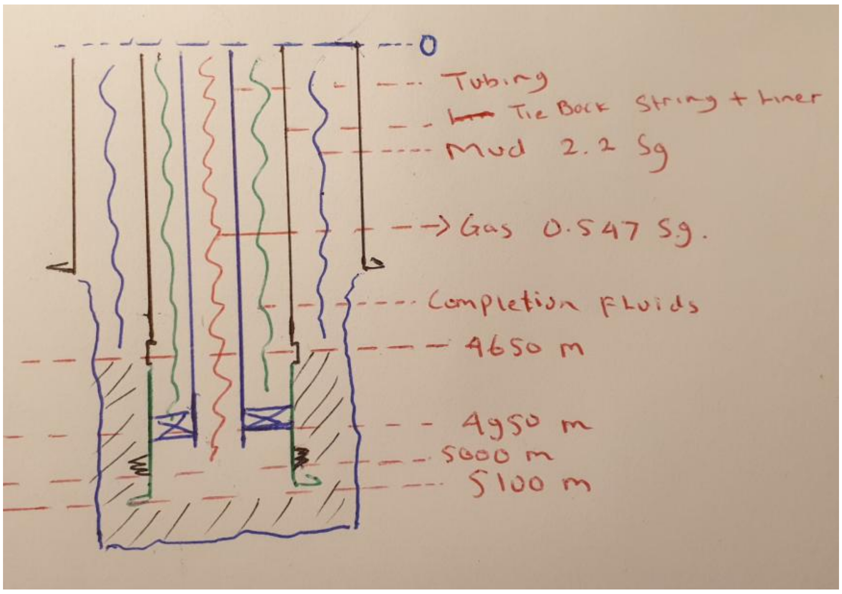
Data for the liner and tie-back string:

7-5/8 in. SMC 110

Weight in air:	625 N/m
Burst resistance:	1005 bar
Collapse resistance:	959 bar
Tensile strength:	6816 kN

Yield factor reduction due to temperature: 0.91

(a) Figure over well – a sketch showing all the given data, students expected to complete this on their own



Assumption :

- Fluid behind tie back string is mud with density 2.2 s.g.
- There is completion fluid above packer with density 2.2 s.g
- Cement has sea water column
- Perforation at 5000 mTVD RT

(b) Define a realistic collapse scenario for the liner. Derate strength to 88% level because of high temperature. Determine the design factor.

<u>Collapse scenario: collapse due to plugged perforations</u>

This is post drilling situation and is realistic in this case as the well has been recommended for further flow testing. Description and assumptions are listed as follows:

- Full reservoir pressure acting on the outside of the liner due to plugged perforations
- The collapse strength will be derated for temperature as per given data
- No biaxial correction needed due to the liner not extending all the way to the wellhead resulting in low axial load. Moreover, the liner is cemented across its entire length
- We will not be accounting for collapse derating due to corrosion. From the available data, we are surmise that this calculation is valid only for flow testing, not for prolonged production. If the well is put on regular production after flow testing, the design factor will have to be re-evaluated to account for corrosion derating
- Assume reservoir gradient of 2.11 SG in the whole liner interval
- Perforation at 5000 mTVD RT

Calculation of collapse design factor for liner:

External Pressure

$P_{@5000}$ = 0.0981 x 2.22 x 5000 = 1034 bar

Internal Pressure

$P_{@5000}$ = 0.0981 x 0.547 x 5000 = 268 bar

ΔP = 1034 - 268
= 766 bar

Derate strength of collapse pressure (P_c) because of temperature = 0.88 x 959 = 844 bar
Design Factor (DF) for Collapse

$DF = \frac{844}{766}$ = 1.1 (OK)

(c) Define two burst criteria. Determine the design factor for burst, and correct for temperature
The tie-back string from the wellhead up to the DST packer (which also includes the top section of the liner) will be designed for the leaking tubing burst criterion. Part of the liner which is below the packer will be designed for possible burst while bull-heading. Calculations for the leaking tubing criterion and the design factor are provided. Since we do not have fracture pressure data for the interval 4950-5100m, only the description of burst while bull-heading will be provided.

Burst criterion 1: leaking tubing criterion

Description and assumptions involved in this criterion are provided as follows:

- For external pressure between liner hanger and packer setting depth, we will use sea water gradient. This is because the liner is fully cemented from the bottom to the liner housing
- For external pressure from wellhead to the liner top (i.e. for the tie back) we will use mud SG because the tie back is NOT cemented to the top
- The internal pressure will use same gradients accordingly, superimposed by the entire tubing pressure, which we assume leaks from below the wellhead

External Pressure

P_0 = 0

P_{4650} = 0.098 x 2.2 x 4650 = 1003 bar

P_{4950} = (0.0981 x (4950-4650) x 1.03) + 1003

= 1033 bar

Internal Pressure

P_0 = (0.0981 x 2.11 x 5000) - (0.0981 x 0.547 x 5000)

= 765 bar

P_{4650} = 765 + (0.0981 x 2.2 x 4650)

= 1768 bar

P_{4950} = 765 + (0.0981 x 2.2 x 4950)

= 1832 bar

ΔP_0 = 765

ΔP_{4650} = 1768 - 1003 = 765

ΔP_{4950} = 1832 - 1033 = 799

Derated burst strength = 0.91 x 1005 = 914.55 bar

Design Factor (DF) for Burst

$DF = \frac{914.55}{799}$ = 1.14 (OK)

Burst criterion 2: burst during bull-heading

Assumption:

- While pumping fluids into the formation, the perforations might get plugged resulting in a pressure build up inside the casing
- Worst case at 5000 meter
- Lower takes full load
- P_{wf} at 5000 m = 2.11 sg

External Pressure

P_{5000} = 0.0981 x 1.03 x 5000 = 505 bar

Internal Pressure

P_{5000} = 0.0981 x 2.2 x 5000

= 1079 bar

ΔP = 1079 - 505 = 574 bar

Derated burst strength = 0.91 x 1005 = 914.55 bar

Design Factor (DF) for Burst

$DF = \frac{914.55}{574}$ = 1.56 (OK)

(d) Define a criterion for tension design. Determine the design factor, including the temperature derating.

Tension loading on the liner will be negligible. The tie back will hang freely from the wellhead and be connected to the liner through a telescopic joint called the polished bore receptacle, hence transmitting no load to the liner. For simplicity, we can neglect buoyancy on the tie back string.

Weight of string in air = 4650 x 625 N/m = 2906.25 KN

Tensile Rating = 0.91 x 6816

= 6202 KN

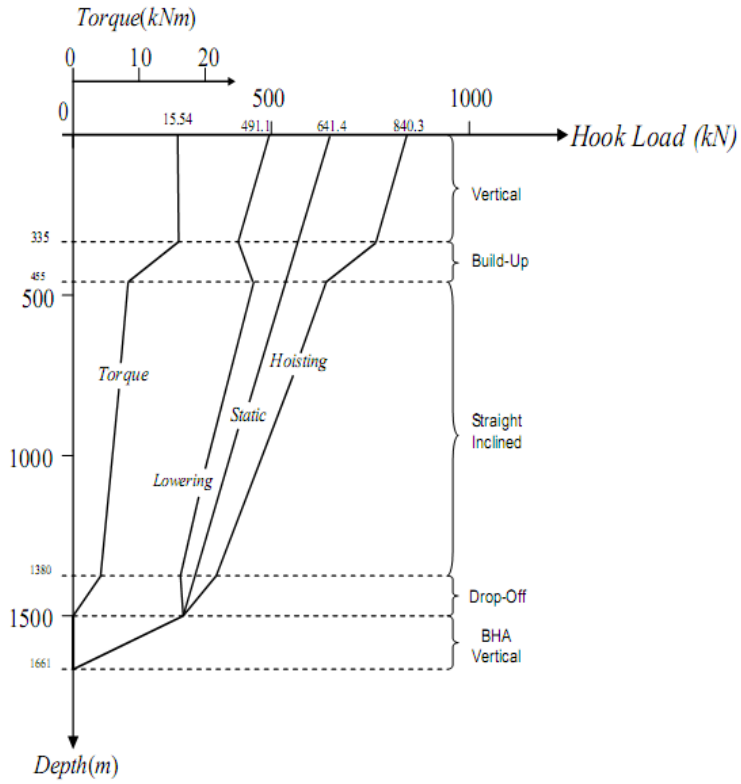
Design Factor (DF) for Tension

$$DF = \frac{6206}{2906} = 2.13 > 1.25 \text{ (OK)}$$

<u>Resume</u>

Load	Burst	Collapse	Tension
NORSOK	1.1	1.1	1.25
Plugged Perforation	-	1.1	-
Shallow tubing Leak	1.14	-	-
Bull Heading	1.56	-	-
Tension	-	-	2.13

Problem 2: Wellbore Friction



(a) Inspection of the force plot reveals that the diagram corresponds to an S-shaped well. The four geometries in this type of well: vertical, build-up section to achieve target inclination, straight inclined section with drop off to vertical at end and terminating in vertical section

(b) Titanium drill pipes are stronger than conventional drill pipes. They should be used in the top of the well because that is where the Load/forces are maximum, as seen on the hook load vs. depth plot

(c) Bends along the well path lead to more friction. The new method derived by Aadnøy, Larsen and Berg (2003), which takes friction into account, results in deeper stuck point in deviated well as compared to a similar vertical well

(d) Hint for this problem (students are encouraged to work out the figure on their own):

> *Static hook load*
>
> The static hook load is equal to the buoyed pipe weight multiplied by the projected vertical height of the well, regardless of wellbore orientation. Thus, a vertical depth D_1 has equal static hookload as a deviated well with the same projected height D_1 (Aadnoy, Larsen and Berg, 1999). Another way of computing the static string weight is to set the coefficient of friction equal to zero for the friction equation defined in the section below.

Ref: Modern Well Design, 2nd edition - Bernt S, Aadnøy

Problem 3: Geomechanics

a. Expression for the horizontal in-situ stress

$P_{wf} = 3\sigma_h - \sigma_H - P_o - \sigma_t$

assume horizontal stresses is equal ($\sigma_h = \sigma_H$) and rock has zero tensile strength because it may contain cracks or fissures ($\sigma_t = 0$)

$P_{wf} = 3\sigma_h - \sigma_h - P_o - 0$

$P_{wf} = 2\sigma_h - P_0$

$$\sigma_h = \frac{P_{wf} + P_o}{2}$$

Select mud weight equal to σ_h

This is called the "Median Line Principle"

b. Use the following equation to calculate LOT value for vertical hole section ($P_{wf}(0)$)

$P_{wf}(0) = \{P_{wf}(\gamma) + (\sigma_0 - 0.5\, P_0)\sin^2\gamma\} / \{1 + 0.5 \sin^2\gamma\}$

Using this equation you will get the results below :

Depth	P_{wf} (0)
890	1.51
1124	1.458
1540	1.44

c. Calculate the horizontal stress

$$\sigma_h = \frac{P_{wf} + P_o}{2}$$

Depth	P_{wf} (0)	P_0	σh
890	1.51	1.03	1.27
1124	1.458	1.21	1.334
1540	1.44	1.3	1.37

This is only valid for isotropic stress state and $\sigma_t = 0$

Problem 4: Hydraulics

(a) Flow in drill string: usually turbulent; flow through drill bit nozzles: turbulent; flow between BHA and annulus: maybe turbulent or laminar; flow in rest of the annulus and riser: laminar

(b) $P_1 = P_2 + P_3$

For details see chapter 2

For laminar flow

$P \sim \mu q$

For turbulent flow

$P \sim \rho f q^2$

For laminar flow, pressure drop is influenced by viscosity (equation 2.9 in course text book).

For turbulent flow, density plays a more direct role in pressure loss (equation 2.10 in course text book).

In a drilling hydraulic system, where flows are usually a mixture of laminar and turbulent regimes, it is difficult to state decisively whether viscosity or density is the driving force behind pressure loss.

(c) Parasitic pressure losses are higher (at equivalent flow rates) when drilling with motor in comparison to rotary drilling (see fig 2.20 in course text book)

(d) - Lower pressure losses

- High annular velocity -> decrease V_{min}

- Increase friction factor

(e) Equation for hydraulic power: used in hydraulic optimization and know as the maximum hydraulic horsepower criterion

Hydraulic HP across bit nozzle is given by= qP_2

P_2 = pressure loss across bit,

q = flow rate

Equation for mechanical power : used in optimization criterion of jet impact force. Refer

Mechanical Power ~ $q\,(P_2)^{1/2}$

Problem 5: Data normalization

(Only the equations for normalization will be described, calculation is left to students)

Normalization equation for converting production platform (air gap 120m, RKB-2) to jack up drilling platform (air gap 40m, RKB-1):

$$P_{RKB-1} = P_{RKB-2}\frac{D}{D - \delta h}$$

Where δh is RKB-2 – RKB-1 = 80 m

For normalizing to sea floor:

$$P_{sf} = P_{RKB-2}\frac{D}{D - h_f - h_w}$$

Where h_f is taken from RKB-2 and this is 120m

h_w = 300